PART 70 PREVENTION OF SIGNIFICANT DETERIORATION
SIGNIFICANT SOURCE MODIFICATION
OFFICE OF AIR QUALITY

Steel Dynamics, Inc.
2601 County Road 700 East
Columbia City, Indiana 46725

(herein known as the Permittee) is hereby authorized to construct and operate subject to the conditions contained herein, the emission units described in Section A (Source Summary) of this approval.

This approval is issued in accordance with 326 IAC 2 and 40 CFR Part 70 Appendix A and contains the conditions and provisions specified in 326 IAC 2-7 as required by 42 U.S.C. 7401, et. seq. (Clean Air Act as amended by the 1990 Clean Air Act Amendments), 40 CFR Part 70.6, IC 13-15 and IC 13-17. This permit is also issued under the provisions of 326 IAC 2-2, 40 CFR 52.21, and 40 CFR 52.124 (Prevention of Significant Deterioration), with conditions listed on the attached pages.

Source Modification No.: 183-15170-00030	
Issued by: Original Signed by Paul Dubenetzky Paul Dubenetzky, Branch Chief Office of Air Quality	Issuance Date: May 31, 2002

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SECTION A SOURCE SUMMARY

This approval is based on information requested by the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ). The information describing the emission units contained in conditions A.1 through A.2 is descriptive information and does not constitute enforceable conditions. However, the Permittee should be aware that a physical change or a change in the method of operation that may render this descriptive information obsolete or inaccurate may trigger requirements for the Permittee to obtain additional permits or seek modification of this approval pursuant to 326 IAC 2, or change other applicable requirements presented in the permit application.

A.1 General Information [326 IAC 2-7-4(c)] [326 IAC 2-7-5(15)]

The Permittee owns and operates a stationary steel beam mill.

Responsible Official:	Richard P. Teets, Jr.
Source Address:	2601 County Road 700 East, Columbia City, Indiana 46725
Mailing Address:	2601 County Road 700 East, Columbia City, Indiana 46725
SIC Code:	3312
County Location:	Whitley
County Status:	Attainment for all criteria pollutants
Source Location Status:	Major source, under PSD Program and Part 70 Program
Source Status:	Part 70 Permit Program Major Source under PSD Rules; Major Source, Section 112 of the Clean Air Act 1 of 28 Source Categories

A.2 Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)] [326 IAC 2-7-5(15)]

This stationary source is approved to construct and operate the following emission unit:

one (1) new ladle vacuum degasser (LVD) with a nominal maximum capacity of 200 tons per hour of steel and one (1) new boiler to power the LVD. Gases from the LVD will be directed to the new boiler for combustion in the boiler. The boiler has a nominal maximum heat input capacity of 41.8 MMBtu per hour, and will use natural gas as the primary fuel, with propane used as an emergency back up fuel. Emissions from the boiler will exhaust through stack 40.

A.3 Specifically Regulated Insignificant Activities [326 IAC 2-7-1(21)] [326 IAC 2-7-4(c)] [326 IAC 2-7-5(15)]

There are no new insignificant activities, as defined in 326 IAC 2-7-1(21), being added through this source modification.

A.4 Part 70 Permit Applicability [326 IAC 2-7-2]

This stationary source is required to have a Part 70 permit by 326 IAC 2-7-2 (Applicability) because:

(a) It is a major source, as defined in 326 IAC 2-7-1(22);

(b) It is a source in a source category designated by the United States Environmental Protection Agency (U.S. EPA) under 40 CFR 70.3 (Part 70 - Applicability).

SECTION B GENERAL CONSTRUCTION CONDITIONS

B.1 Definitions [326 IAC 2-7-1]

Terms in this permit shall have the definition assigned to such terms in the referenced regulation. In the absence of definitions in the referenced regulation, the applicable definitions found in the statutes or regulations (IC 13-11, 326 IAC 1-2 and 326 IAC 2-7) shall prevail.

B.2 Effective Date of the Permit [40CFR 124]

Pursuant to 40 CFR 124.15, 40 CFR 124.19, and 40 CFR 124.20, the effective date of this permit will be thirty (30) days after the service of notice of the decision, except as provided in 40 CFR 124. Three (3) days shall be added to the thirty (30) day period if service of notice is by U.S. postal mail.

B.3 Revocation of Permits [326 IAC 2-2-8]

Pursuant to 40 CFR 52.21(r)(2) and 326 IAC 2-2-8(a)(1), this permit to construct shall expire if construction is not commenced within eighteen (18) months after receipt of this approval, if construction is discontinued for a continuous period of eighteen (18) months or more, or if construction is not completed within a reasonable time. The IDEM may extend the eighteen (18) month period upon satisfactory showing that an extension is justified.

B.4 Significant Source Modification [326 IAC 2-7-10.5(h)]

This document shall also become the approval to operate pursuant to 326 IAC 2-7-10.5(h) when the following requirements are met:

(a) The attached affidavit of construction shall be submitted to the Office of Air Quality (OAQ), Permit Administration & Development Section, verifying that the emission units were constructed as proposed in the application. The emissions units covered in the Significant Source Modification approval may begin operating on the date the affidavit of construction is postmarked or hand delivered to IDEM if constructed as proposed.

(b) If actual construction of the emissions units differs from the construction proposed in the application, the source may not begin operation until the source modification has been revised pursuant to 326 IAC 2-7-11 or 326 IAC 2-7-12 and an Operation Permit Validation Letter is issued.

(c) If construction is completed in phases; i.e., the entire construction is not done continuously, a separate affidavit must be submitted for each phase of construction. Any permit conditions associated with operation start up dates such as stack testing for New Source Performance Standards (NSPS) shall be applicable to each individual phase.

(d) The Permittee shall receive an Operation Permit Validation Letter from the Chief of the Permit Administration & Development Section and attach it to this document.

B.5 NSPS Reporting Requirement [40 CFR 60, Subpart Dc]

Pursuant to the New Source Performance Standards (NSPS), Part 60, Subpart Dc, the source owner/operator is hereby advised of the requirement to report the following at the appropriate times:

(a) Commencement of construction date (no later than 30 days after such date);

(b) Anticipated start-up date (not more than 60 days or less than 30 days prior to such date); and

(c) Actual start-up date (within 15 days after such date).

Reports are to be sent to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, IN 46206-6015

The application and enforcement of these standards have been delegated to the IDEM, OAQ. The requirements of 40 CFR Part 60 are also federally enforceable.

SECTION C GENERAL OPERATION CONDITIONS

C.1 Certification [326 IAC 2-7-4(f)][326 IAC 2-7-6(1)][326 IAC 2-7-5(3)(C)]

(a) Where specifically designated by this permit or required by an applicable requirement, any application form, report, or compliance certification submitted shall contain certification by a responsible official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(b) One (1) certification shall be included, using the attached Certification Form or its equivalent, with each submittal requiring certification.

(c) A responsible official is defined at 326 IAC 2-7-1(34).

C.2 Preventive Maintenance Plan [326 IAC 2-7-5(1),(3) and (13)] [326 IAC 2-7-6(1) and (6)] [326 IAC 1-6-3]

(a) If required by specific condition(s) in Section D of this permit, the Permittee shall prepare and maintain a Preventive Maintenance Plan (PMP). The PMP shall be prepared prior to the start of operation of the emission unit listed in this permit, and shall include the following information:

(1) Identification of the individual(s) responsible for inspecting, maintaining, and repairing emission control devices;

(2) A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions; and

(3) Identification and quantification of the replacement parts that will be maintained in inventory for quick replacement.

If, due to circumstances beyond the Permittee's control, the PMP cannot be prepared and maintained prior to the start of operation of the emission unit listed in this permit, the Permittee may extend the date an additional ninety (90) days provided the Permittee notifies:

Indiana Department of Environmental Management
Compliance Branch, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

The PMP and the PMP extension notification do not require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(b) The Permittee shall implement the PMP as necessary to ensure that failure to implement a PMP does not cause or contribute to a violation of any limitation on emissions or potential to emit.

(c) A copy of the PMP shall be submitted to IDEM, OAQ, upon request and within a reasonable time, and shall be subject to review and approval by IDEM, OAQ. IDEM, OAQ, may require the Permittee to revise its PMP whenever lack of proper maintenance causes or contributes to any violation. The PMP does not require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(d) Records of preventive maintenance shall be retained for a period of at least five (5) years. These records shall be kept at the source location for a minimum of three (3) years. The records may be stored elsewhere for the remaining two (2) years as long as they are available upon request. If the Commissioner makes a request for records to the Permittee, the Permittee shall furnish the records to the Commissioner within a reasonable time.

C.3 Permit Amendment or Modification [326 IAC 2-7-11] [326 IAC 2-7-12]

(a) Permit amendments and modifications are governed by the requirements of 326 IAC 2-7-11 or 326 IAC 2-7-12 whenever the Permittee seeks to amend or modify this permit.

(b) Any application requesting an amendment or modification of this permit shall be submitted to:

Indiana Department of Environmental Management
Permits Branch, Office of Air Quality
100 North Senate Avenue, P.O. Box 6015
Indianapolis, Indiana 46206-6015

Any such application shall be certified by the "responsible official" as defined by 326 IAC 2-7-1(34).

(c) The Permittee may implement administrative amendment changes addressed in the request for an administrative amendment immediately upon submittal of the request. [326 IAC 2-7-11(c)(3)]

C.4 Opacity [326 IAC 5-1]

Pursuant to 326 IAC 5-1-2 (Opacity Limitations), except as provided in 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), opacity shall meet the following, unless otherwise stated in this permit:

(a) Opacity shall not exceed an average of forty percent (40%) in any one (1) six (6) minute averaging period as determined in 326 IAC 5-1-4.

(b) Opacity shall not exceed sixty percent (60%) for more than a cumulative total of fifteen (15) minutes (sixty (60) readings as measured according to 40 CFR 60, Appendix A, Method 9 or fifteen (15) one (1) minute nonoverlapping integrated averages for a continuous opacity monitor) in a six (6) hour period.

C.5 Fugitive Dust Emissions [326 IAC 6-4]

The Permittee shall not allow fugitive dust to escape beyond the property line or boundaries of the property, right-of-way, or easement on which the source is located, in a manner that would violate 326 IAC 6-4 (Fugitive Dust Emissions). 326 IAC 6-4-2(4) is not federally enforceable.

Testing Requirements [326 IAC 2-7-6(1)]

C.6 Performance Testing [326 IAC 3-6][326 IAC 2-1.1-11]

(a) Compliance testing on the new emission unit shall be conducted not later than 60 days after achieving maximum production rate, and not later than 180 days after initial start-up, if specified in Section D of this approval. All testing shall be performed according to the provisions of 326 IAC 3-6 (Source Sampling Procedures), except as provided elsewhere in this approval, utilizing any applicable procedures and analysis methods specified in 40 CFR 51, 40 CFR 60, 40 CFR 61, 40 CFR 63, 40 CFR 75, or other procedures approved by IDEM, OAQ.

A test protocol, except as provided elsewhere in this approval, shall be submitted to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

no later than thirty-five (35) days prior to the intended test date. The protocol submitted by the Permittee does not require certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(b) The Permittee shall notify IDEM, OAQ of the actual test date at least fourteen (14) days prior to the actual test date. The notification submitted by the Permittee does not require certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(c) Pursuant to 326 IAC 3-6-4(b), all test reports must be received by IDEM, OAQ not later than forty-five (45) days after the completion of the testing. An extension may be granted by IDEM, OAQ, if the source submits to IDEM, OAQ, a reasonable written explanation within five (5) days prior to the end of the initial forty-five (45) day period.

Compliance Requirements [326 IAC 2-1.1-11]

C.7 Compliance Requirements [326 IAC 2-1.1-11]

The commissioner may require stack testing, monitoring, or reporting at any time to assure compliance with all applicable requirements. Any monitoring or testing shall be performed in accordance with 326 IAC 3 or other methods approved by the commissioner or the U. S. EPA.

Compliance Monitoring Requirements [326 IAC 2-7-5(1)] [326 IAC 2-7-6(1)]

C.8 Compliance Monitoring [326 IAC 2-7-5(3)] [326 IAC 2-7-6(1)]

If required by Section D, all monitoring and record keeping requirements shall be implemented when operation begins. As required by Section D, the Permittee shall be responsible for installing any necessary equipment and initiating any required monitoring related to that equipment.

Corrective Actions and Response Steps [326 IAC 2-7-5] [326 IAC 2-7-6]

C.9 Compliance Response Plan - Preparation, Implementation, Records, and Reports [326 IAC 2-7-5] [326 IAC 2-7-6]

(a) The Permittee is required to prepare Compliance Response Plan (CRP) procedures for each compliance monitoring condition of this permit. A CRP shall be submitted to IDEM, OAQ upon request. The CRP shall be prepared prior to startup of the new emission unit by the Permittee, supplemented from time to time by the Permittee, maintained on site, and comprised of:

(1) Reasonable response steps that may be implemented in the event that a response step is needed pursuant to the requirements of Section D of this permit; and an expected time frame for taking reasonable response steps.

(2) If, at any time, the Permittee takes reasonable response steps that are not set forth in the Permittee’s current Compliance Response Plan and the Permittee documents such response in accordance with subsection (e) below, the

Permittee shall amend its Compliance Response Plan to include such response steps taken.

(b) For each compliance monitoring condition of this permit, reasonable response steps shall be taken when indicated by the provisions of that compliance monitoring condition as follows:

(1) Reasonable response steps shall be taken as set forth in the Permittee's current Compliance Response Plan; or

(2) If none of the reasonable response steps listed in the Compliance Response Plan is applicable or responsive to the excursion, the Permittee shall devise and implement additional response steps as expeditiously as practical. Taking such additional response steps shall not be considered a deviation from this permit so long as the Permittee documents such response steps in accordance with this condition.

(3) If the Permittee determines that additional response steps would necessitate that the emissions unit or control device be shut down, the IDEM, OAQ shall be promptly notified of the expected date of the shut down, the status of the applicable compliance monitoring parameter with respect to normal, and the results of the actions taken up to the time of notification.

(4) Failure to take reasonable response steps shall constitute a violation of the permit.

(c) The Permittee is not required to take any further response steps for any of the following reasons:

(1) A false reading occurs due to the malfunction of the monitoring equipment and prompt action was taken to correct the monitoring equipment.

(2) The Permittee has determined that the compliance monitoring parameters established in the permit conditions are technically inappropriate, has previously submitted a request for a permit modification to the permit, and such request has not been denied.

(3) An automatic measurement was taken when the process was not operating.

(4) The process has already returned or is returning to operating within "normal" parameters and no response steps are required.

(d) When implementing reasonable steps in response to a compliance monitoring condition, if the Permittee determines that an exceedance of an emission limitation has occurred, the Permittee shall report such deviations pursuant to Section B-Deviations from Permit Requirements and Conditions.

(e) The Permittee shall record all instances when response steps are taken. In the event of an emergency, the provisions of 326 IAC 2-7-16 (Emergency Provisions) requiring prompt corrective action to mitigate emissions shall prevail.

(f) Except as otherwise provided by a rule or provided specifically in Section D, all monitoring as required in Section D shall be performed when the emission unit is operating, except for time necessary to perform quality assurance and maintenance activities.

C.11 Emergency Provisions [326 IAC 2-7-16]

(a) An emergency, as defined in 326 IAC 2-7-1(12), is not an affirmative defense for an action brought for noncompliance with a federal or state health-based emission limitation.

(b) An emergency, as defined in 326 IAC 2-7-1(12), constitutes an affirmative defense to an action brought for noncompliance with a technology-based emission limitation if the affirmative defense of an emergency is demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that describe the following:

(1) An emergency occurred and the Permittee can, to the extent possible, identify the causes of the emergency;

(2) The permitted facility was at the time being properly operated;

(3) During the period of an emergency, the Permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit;

(4) For each emergency lasting one (1) hour or more, the Permittee notified IDEM, OAQ, within four (4) daytime business hours after the beginning of the emergency, or after the emergency was discovered or reasonably should have been discovered;

Telephone Number: 1-800-451-6027 (ask for Office of Air Quality, Compliance Section), or
Telephone Number: 317-233-5674 (ask for Compliance Section)
Facsimile Number: 317-233-5967

(5) For each emergency lasting one (1) hour or more, the Permittee submitted the attached Emergency Occurrence Report Form or its equivalent, either by mail or facsimile to:

Indiana Department of Environmental Management
Compliance Branch, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

within two (2) working days of the time when emission limitations were exceeded due to the emergency.

The notice fulfills the requirement of 326 IAC 2-7-5(3)(C)(ii) and must contain the following:

(A) A description of the emergency;

(B) Any steps taken to mitigate the emissions; and

(C) Corrective actions taken.

The notification which shall be submitted by the Permittee does not require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(6) The Permittee immediately took all reasonable steps to correct the emergency.

(c) In any enforcement proceeding, the Permittee seeking to establish the occurrence of an emergency has the burden of proof.

(d) This emergency provision supersedes 326 IAC 1-6 (Malfunctions). This permit condition is in addition to any emergency or upset provision contained in any applicable requirement.

(e) IDEM, OAQ, may require that the Preventive Maintenance Plan required under 326 IAC 2-7-4-(c)(10) be revised in response to an emergency.

(f) Failure to notify IDEM, OAQ, by telephone or facsimile of an emergency lasting more than one (1) hour in accordance with (b)(4) and (5) of this condition shall constitute a violation of 326 IAC 2-7 and any other applicable rules.

(g) If the emergency situation causes a deviation from a technology-based limit, the Permittee may continue to operate the affected emitting facilities during the emergency provided the Permittee immediately takes all reasonable steps to correct the emergency and minimize emissions.

C.12 Actions Related to Noncompliance Demonstrated by a Stack Test [326 IAC 2-7-5] [326 IAC 2-7-6]

(a) When the results of a stack test performed in conformance with Section C - Performance Testing, of this permit exceed the level specified in any condition of this permit, the Permittee shall take appropriate response actions. The Permittee shall submit a description of these response actions to IDEM, OAQ, not later than thirty (30) days after receipt of the test results. The Permittee shall take appropriate action to minimize excess emissions from the affected facility while the response actions are being implemented.

(b) A retest to demonstrate compliance shall be performed not later than one hundred twenty (120) days after receipt of the original test results. Should the Permittee demonstrate to IDEM, OAQ that retesting in one-hundred and twenty (120) days is not practicable, IDEM, OAQ may extend the retesting deadline.

(c) IDEM, OAQ reserves the authority to take any actions allowed under law in response to noncompliant stack tests.

The documents submitted pursuant to this condition do require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

C.13 General Record Keeping Requirements [326 IAC 2-7-5(3)][326 IAC 2-7-6]

(a) Records of all required data, reports and support information shall be retained for a period of at least five (5) years from the date of monitoring sample, measurement, report, or application. These records shall be kept at the source location for a minimum of three (3) years. The records may be stored elsewhere for the remaining two (2) years as long as they are available upon request. If the Commissioner makes a request for records to the Permittee, the Permittee shall furnish the records to the Commissioner within a reasonable time.

(b) Unless otherwise specified in this permit, all record keeping requirements not already legally required shall be implemented when operation of the emission unit begins.

C.14 General Reporting Requirements [326 IAC 2-7-5(3)(C)]

(a) The reports required by conditions in Section D of this permit shall be submitted to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

(b) Unless otherwise specified in this permit, any notice, report, or other submission required by this permit shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ, on or before the date it is due.

(c) Unless otherwise specified in this permit, all reports required in Section D of this permit shall be submitted not later than thirty (30) days after the end of the reporting period. Unless otherwise specified in this permit, all reports do require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

(d) The first report shall cover the period commencing on the date of startup of the emission unit and ending on the last day of the reporting period. Reporting periods are based on calendar years.

SECTION D.1 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)]

one (1) new ladle vacuum degasser (LVD) with a nominal maximum capacity of 200 tons per hour of steel and one (1) new boiler to power the LVD. Gases from the LVD will be directed to the new boiler for combustion in the boiler. The boiler has a nominal maximum heat input capacity of 41.8 MMBtu per hour, and will use natural gas as the primary fuel, with propane used as an emergency back up fuel. Emissions from the boiler will exhaust through stack 40.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-7-5(1)]

D.1.1 PM/PM10 Limitations (PM) [326 IAC 2-2-3] [326 IAC 6-2-4]

(a) Pursuant to 326 IAC 2-2-3 (PSD), the total PM/PM10 (including both filterable and condensible) emissions from the LVD boiler shall not exceed 0.0076 pound per million Btu of heat input and 0.318 pound per hour.

(b) Pursuant to 326 IAC 6-2-4 (Particulate emission limitations for sources of indirect heating: emission limitations for facilities specified in 326 IAC 6-2-1(d)), particulate emissions from the boiler shall not exceed 0.1 pound per million Btu of heat input.

D.1.2 NOx Limitations (PM) [326 IAC 2-2-3]

Pursuant to 326 IAC 2-2-3 (PSD), the NOx emissions from the LVD boiler shall not exceed 0.04 pound per million Btu of heat input and 1.67 pounds per hour, unless these limits are adjusted as follows. If the stack test required under Condition D.1.8 shows that these NOx limits are not achievable in practice for the vacuum degasser boiler, the Department may revise the permit to adjust these NOx limitations. If the stack test required under Condition D.1.8 shows that more stringent NOx limits are achievable, the Department may, at its discretion, use the authority under IC 13-15-7-2 to re-open and revise the limit to more closely reflect the actual stack test results. The Department will provide an opportunity for public notice and comment prior to finalizing any permit revision. IC 13-15-7-3 (Revocation or Modification of a Permit: Appeal to Board) shall apply to this permit condition. Any relaxation of the emission limit will require an air quality analysis that ensures protection of the NAAQS and compliance with the PSD increment.

D.1.3 CO Limitations (PM) [326 IAC 2-2-3]

Pursuant to 326 IAC 2-2-3 (PSD), the CO emissions from the LVD boiler shall not exceed 0.084 pound per million Btu of heat input and 3.51 pounds per hour, unless these limits are adjusted as follows. If the stack test required under Condition D.1.8 shows that these CO limits are not achievable in practice for the vacuum degasser boiler, the Department may revise the permit to adjust these CO limitations. If the stack test required under Condition D.1.8 shows that more stringent CO limits are achievable, the Department may, at its discretion, use the authority under IC 13-15-7-2 to re-open and revise the limit to more closely reflect the actual stack test results. The Department will provide an opportunity for public notice and comment prior to finalizing any permit revision. IC 13-15-7-3 (Revocation or Modification of a Permit: Appeal to Board) shall apply to this permit condition. Any relaxation of the emission limit will require an air quality analysis that ensures protection of the NAAQS and compliance with the PSD increment.

D.1.4 VOC Limitations (PM) [326 IAC 2-2-3]

Pursuant to 326 IAC 2-2-3 (PSD), the VOC emissions from the LVD boiler shall not exceed 0.0026 pound per million Btu of heat input and 0.11 pound per hour.

D.1.5 SO_2 Limitations (PM) [326 IAC 2-2-3]

Pursuant to 326 IAC 2-2-3 (PSD), the SO_2 emissions from the LVD boiler shall not exceed 0.0006 pound per million Btu of heat input and 0.025 pound per hour.

D.1.6 Operating Parameters [326 IAC 2-2-3]

Pursuant to 326 IAC 2-2-3 (PSD), the following conditions shall apply:

(a) Only natural gas or propane fuels shall be used in the LVD boiler.

(b) The amount of natural gas used in the LVD boiler shall not exceed 209 million cubic feet per 12 consecutive month period.

(c) The amount of propane used in the LVD boiler shall not exceed 222 kilogallons per 12 consecutive month period.

(d) Combustion emissions shall be reduced through the use of good combustion practices.

D.1.7 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan, in accordance with Section C - Preventive Maintenance Plan, of this permit, is required for the LVD boiler.

Compliance Determination Requirements

D.1.8 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]

Not later than 60 days after achieving maximum capacity, and not later than 180 days after startup, the Permittee shall perform NOx and CO testing on the LVD boiler using methods as approved by the Commissioner. Testing shall be performed in compliance with Section C - Performance Testing.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.1.9 Record Keeping Requirements [40 CFR 60, Subpart Dc]

(a) Pursuant to 40 CFR 60, Subpart Dc, the Permittee shall maintain records of the amount of each type of fuel combusted in the LVD boiler each day.

(b) In order to demonstrate compliance with Condition D.1.6 (b) and (c), the Permittee shall maintain records of the natural gas and propane usages in the LVD boiler each month.

(c) All records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

D.1.10 Reporting Requirements

A quarterly summary of the information to document compliance with Condition D.1.6 (b) and (c) shall be submitted to the address listed in Section C - General Reporting Requirements, of this permit, using the reporting form located at the end of this permit, or its equivalent, not later than thirty (30) days after the end of the quarter being reported. The report submitted by the Permittee does require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY

PART 70 SOURCE MODIFICATION CERTIFICATION

Source Name:	Steel Dynamics, Inc.
Source Address:	2601 County Road 700 East, Columbia City, IN 46725
Mailing Address:	2601 County Road 700 East, Columbia City, IN 46725
Source Modification No.:	183-15170-00030

This certification shall be included when submitting monitoring, testing reports/results or other documents as required by this approval.

Please check what document is being certified:

9 Test Result (specify) ____________________

9 Report (specify) ____________________

9 Notification (specify) ____________________

9 Affidavit (specify) ____________________

9 Other (specify) ____________________

I certify that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

Signature:
Printed Name:
Title/Position:
Date:

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

Part 70 Source Modification Quarterly Report

Source Name:	Steel Dynamics, Inc.
Source Address:	2601 County Road 700 East, Columbia City, IN 46725
Mailing Address:	2601 County Road 700 East, Columbia City, IN 46725
Source Modification No.:	183-15170-00030
Facility:	LVD boiler
Parameters:	natural gas and propane usages
Limits:	209 MMCF of natural gas per twelve consecutive month period and 222 kilogallons of propane per twelve consecutive month period

YEAR: _______________

Month		Column 1	Column 2	Column 1 + Column 2
	Fuel	This Month	Previous 11 Months	12 Month Total
Month 1	Natural gas (MMCF)			
	Propane (kgal)			
Month 2	Natural gas (MMCF)			
	Propane (kgal)			
Month 3	Natural gas (MMCF)			
	Propane (kgal)			

9 No deviation occurred in this quarter.

9 Deviation/s occurred in this quarter.
Deviation has been reported on: ______________________

Submitted by: ____
Title / Position: ____
Signature: ____
Date: ____
Phone: ____

Attach a signed certification to this report.

Mail to: Permit Administration & Development Section
Office Of Air Quality
100 North Senate Avenue
P. O. Box 6015
Indianapolis, Indiana 46206-6015

Steel Dynamics, Inc.
2601 County Road 700 East
Columbia City, Indiana 46725

Affidavit of Construction

I, ______________________________________, being duly sworn upon my oath, depose and say:
(Name of the Authorized Representative)

1. I live in ____________________________ County, Indiana and being of sound mind and over twenty-one (21) years of age, I am competent to give this affidavit.

2. I hold the position of ______________________ for _______________________.
(Title) (Company Name)

3. By virtue of my position with _______________________________,I have personal
(Company Name)

knowledge of the representations contained in this affidavit and am authorized to make

these representations on behalf of ____ .
(Company Name)

4. I hereby certify that Steel Dynamics, Inc., 2601 County Road 700 East, Columbia City, Indiana, 46725, has constructed the ladle vacuum degasser and boiler in conformity with the requirements and intent of the construction permit application received by the Office of Air Quality on December 18, 2001 and as permitted pursuant to **Source Modification No. 183–15170-00030** issued on ____________________

Further Affiant said not.

I affirm under penalties of perjury that the representations contained in this affidavit are true, to the best of my information and belief.

____
Signature

____
Date

STATE OF INDIANA)
)SS

COUNTY OF ____________________)

Subscribed and sworn to me, a notary public in and for _________________________ County and State of

Indiana on this ___________________ day of ______________________, 20 _________ .

My Commission expires: _________________________

____
Signature

____
Name (typed or printed)

Indiana Department of Environmental Management
Office of Air Quality

Addendum to the
Technical Support Document for a Significant Source Modification
to a Part 70 Operating Permit

Source Name:	Steel Dynamics, Inc.
Source Location:	2601 County Road 700 East, Columbia City, Indiana 46725
County:	Whitley
SIC Code:	3312
Operation Permit No.:	None
Operation Permit Issuance Date:	not yet issued
Significant Source Modification No.:	183-15170-00030
Permit Reviewer:	Nisha Sizemore

On March 14, 2002, the Office of Air Quality (OAQ) had a notice published in the Columbia City Post-Mail, Columbia City, Indiana, stating that Steel Dynamics, Inc. had applied for a Significant Source Modification to a Part 70 source for the construction of a natural gas-fired boiler and a vacuum degasser. The notice also stated that OAQ proposed to issue a permit for this operation and provided information on how the public could review the proposed permit and other documentation. Finally, the notice informed interested parties that there was a period of thirty (30) days to provide comments on whether or not this permit should be issued as proposed. A public hearing was also held on April 17, 2002.

On April 17, 2002, Daniel and Sandy Trimmer, submitted written and oral comments on the proposed significant source modification to the Part 70 permit. A summary of the comments is as follows.

Comment #1

We have serious reservations about why this was not added to the original permit, following the addition of rail production to SDI's plans. In June of 1999, long before SDI received their construction permit, at least one member of Citizens Organized Watch, Inc. (COW) asked the IDEM directly in an e-mail, if there would be additional emissions from the manufacturing of rails. The IDEM was told by the source (SDI), that this would stay within their threshold of pollutants and that no additional pollution sources would be added. As we have found, the IDEM was given the incorrect information once again by SDI. The truth has been withheld from the public, and in violation of the letter and spirit of the Clean Air Act and New Source Review. The law allows the IDEM to go directly to the source for information, but when the information is withheld from the IDEM by the source, there must be consequences administered and strictly enforced. IDEM risks its credibility, effectiveness, and loss of its authority to administer such programs, when the authority of IDEM is in question.

Response #1

Steel Dynamics applied for this application to install and operate a new vacuum degasser boiler only after learning that potential new customers required steel rails with specifications that would require the use of the vacuum degassing process. Since none of the plant operations have begun operating, and construction of the new plant has not yet been completed, IDEM reviewed this application as though it was part of the original permit application to construct the entire plant. As a result, it was reviewed pursuant to the requirements of PSD. The emissions from the new vacuum degasser boiler alone are not in excess of the PSD significance levels; therefore, if the vacuum degasser boiler had been permitted separately, as suggested by the commenter, it would not have been required to comply with the requirements of PSD. For administrative purposes, IDEM issued a separate permit document to SDI for the vacuum degasser boiler. However, PSD applicability was based on the combined emissions from the proposed vacuum degasser boiler and the emissions from the rest of the plant processes.

Comment #2

The natural gas fired boiler and the ladle vacuum degasser are located in the melt shop. The significant permit modification number 183-12692-00030 for SDI and the PSD permit number 183-10097-00030 require SDI to totally enclose the melt shop with all emissions routed to one baghouse. Because of the location of this new emission unit, it is achievable to route this to the existing baghouse and therefore keeping the integrity of totally enclosed melt shop as stated in the significant modification. We urge IDEM to further study the feasibility of exhausting stack 40 into the existing baghouse.

Response #2

The maximum potential to emit particulate matter from the proposed uncontrolled vacuum degasser boiler is 0.318 pound per hour, which is equivalent to an outlet grain loading of 0.0035 grains per dry standard cubic foot per minute (gr/dscf). SDI's permit #183-12692-00030 issued January 10, 2001, established particulate matter limits for the meltshop baghouse. The limits are 0.0018 gr/dscf for filterable particulate and 0.0052 gr/dscf for total particulate. Since the outlet particulate grain loading of the baghouse is greater than the outlet grain loading of the uncontrolled vacuum degasser boiler, venting the vacuum degasser boiler to the meltshop baghouse would not succeed in reducing particulate emissions. More likely, the increased air flow to the baghouse would only make the baghouse less efficient in controlling the particulate emissions from the other units in the meltshop. Additionally, IDEM is not aware of any other facility using a baghouse to control particulate emissions from a natural gas-fired boiler. There has been no change to the permit as a result of this comment.

On April 17, 2002, Charles G. Kille, submitted written and oral comments on the proposed significant source modification to the Part 70 permit. A summary of the comments is as follows.

Comment #1

The title page of the draft permit references "40 CFR Part 70 Appendix A. Please explain this reference as I can find only 40 CFR Part 70.1 through 40 CFR Part 70.11. (Appendix A is the issue).

Response #1

40 CFR Part 70 Appendix A provides information on the approval status of state and local operating permit programs. As a courtesy, IDEM has separately provided Mr. Kille a copy of 40 CFR Part 70, Appendix A.

Comment #2

Has there been a recent inspection of the facility here in Whitley County looking for evidence of construction for this emission unit? With an outstanding Notice of Violation for beginning construction of the plant without an effective PSD permit, it would seem only prudent to do so. We therefore respectfully request that IDEM conduct an inspection and include the results with the responses to these comments prior to issuing any final decision for this modification.

Response #2

On May 1, 2002, Jennifer Dorn, an IDEM inspector conducted an inspection of the Whitley County SDI facility. The inspector found no evidence that the Permittee had begun any construction on the vacuum degasser or the boiler.

Comment #3

This permit modification lists the subject equipment as required for the process used to make the steel used to produce the head hardened railroad rails. IDEM was aware of the sources plans for the production of these rails prior to the issuance of the original PSD permit. IDEM assured the public, on several occasions and in writing/e-mail, that the capacity of the permit limits would not be exceeded by the additional production and that the rail production required no new emission sources. It seems plainly evident with this application and proposed modification that this was not the case and it also seems that relevant information was fraudulently withheld during consideration of the original PSD permit. If this is the case, then the public has been denied an opportunity to review the entire new source planned by the applicant. It is very difficult to believe, after all we've been through, that the applicant was anything but fully aware of their obligation to include all emission sources in their PSD application. Even more difficult to believe that they did not understand what equipment was needed. They are fully responsible for disclosing that information.

The IDEM is aware of this company's recent performance and difficulties meeting it's obligations under the Clean Air Act, New Source Review, and PSD programs, and make a short mention of the outstanding Notices of Violation. This company's past, recent, and current performance and attitude must be considered as factors that bear on these proceedings. IDEM's delegated authority includes obligations to monitor and enforce. Why does the IDEM continue to remain complacent and allow this applicant to flaunt the regulations unchallenged?

In consideration of the timing of this application, the IDEM has forced this action to be considered a major modification even though the isolated emissions would not require it. Effectively, the advantage to the public is that it provides a public review and comment period prior to the IDEM fully approving the source modification.

The IDEM must consider this additional emission unit in the context of the entire construction project, facility and PSD permit as if it had been properly included. To do otherwise is to reward SDI for withholding relevant information.

Response #3

Steel Dynamics applied for this application to install and operate a new vacuum degasser boiler only after learning that potential new customers required steel rails with specifications that would require the use of the vacuum degassing process. Since none of the plant operations have begun operating, and construction of the new plant has not yet been completed, IDEM reviewed this application as though it were part of the original permit application to construct the entire plant. The emissions from the new vacuum degasser boiler alone are not in excess of the PSD significance levels; therefore, if the vacuum degasser boiler had been permitted separately, as suggested by the commenter, it would not have been required to comply with the requirements of PSD. For administrative purposes, IDEM issued a separate permit document to SDI for the vacuum degasser boiler. However, PSD applicability was based on the combined emissions from the proposed vacuum degasser boiler and the emissions from the rest of the plant processes. As a result, the vacuum degasser boiler was reviewed pursuant to the requirements of PSD, including an analysis of Best Available Control Technology (BACT). An air quality analysis was performed that demonstrates that the emissions from the entire source, including the new boiler, will not cause or contribute to a violation of any air quality standard. By reviewing the proposed vacuum degasser boiler pursuant to the requirements of PSD, IDEM has treated the project as though it were part of the original application, and there has been no circumvention of the Clean Air Act requirements.

IDEM does not have specific authority to deny the permit based on the compliance status of other Steel Dynamics plants at other locations. Additionally, IDEM is not pursuing any enforcement actions against the Steel Dynamics Columbia City plant. The EPA is pursuing an enforcement action against the Steel Dynamics Columbia City plant because the EPA alleges that SDI began construction prior to receiving their final permit.

Comment #4

What is the physical location of this emission source in reference to the rest of the facility? It seems plausible that it would be located in the area of the melt shop. Emissions of equipment within the melt shop, direct, fugitive and otherwise must be considered for inclusion within the controls provided by the totally enclosed melt shop configuration imposed by the original PSD. Proper consideration of this emission unit as part of the original plan of this facility must be demanded by the IDEM. The additional emissions of this unit should not be considered in total isolation from the balance of the facility and the opportunities it offers for efficiency. This unit should also be considered as part of the initial construction project.

The BACT analysis did not consider the existing emission control options already required and is therefore flawed and must be reworked to include these considerations.

Response #4

The vacuum degassing process will occur at the ladle metallurgical facility (LMF), which is located in the meltshop. When making rail, SDI will attach the vacuum degasser to the ladle. The actual degassing of steel is estimated to take from 30 to 60 minutes per batch, during which time the degasser air flow is directed into the boiler.

The maximum potential to emit particulate matter from the proposed uncontrolled vacuum degasser boiler is 0.318 pound per hour, which is equivalent to an outlet grain loading of 0.0035 grains per dry standard cubic foot per minute (gr/dscf). SDI's permit #183-12692-00030 issued January 10, 2001, established particulate matter limits for the meltshop baghouse. The limits are 0.0018 gr/dscf for filterable particulate and 0.0052 gr/dscf for total particulate. Since the outlet particulate grain loading of the baghouse is greater than the outlet grain loading of the uncontrolled vacuum degasser boiler, venting the vacuum degasser boiler to the meltshop baghouse would not succeed in reducing particulate emissions. More likely, the increased air flow to the baghouse would only make the baghouse less efficient in controlling the particulate emissions from the other units in the meltshop. Additionally, IDEM is not aware of any other facility using a baghouse to control particulate emissions from a natural gas-fired boiler.

The addition of the vacuum ladle degasser does not change the emission limits on the meltshop baghouse, which were established by permit #183-12692-00030 issued January 10, 2001. Additionally, the meltshop is still required to be totally enclosed and the opacity from the meltshop cannot exceed 3% from any building opening. This opacity limit effectively limits visible emissions from all units located in the meltshop, including the proposed new vacuum degasser boiler, since it will also be located in the meltshop.

Comment #5

The BACT analysis did not consider the gas and steam exhaust stream from the molten steel as a source of PM/PM10 and therefore the BACT analysis is not complete and must be reworked.

Response #5

Gases from the vacuum degasser will pass through a hotwell, then exhaust directly to the natural gas-fired boiler. The hotwell is a large covered concrete container of water. The degassing process itself is not expected to generate any additional particulate matter at the LMF. However the vacuum created by the degasser may collect a small amount of the particulate matter generated by the LMF. The particulate matter, if any, that is collected by the vacuum degasser would be caught in the hotwell and not exhausted from the degasser itself. Further, any exhaust through the boiler stack must meet the limits in Condition D.1.1. As a result, the BACT analysis is not incomplete and no change is necessary to the permit.

Comment #6

The permit mentions that the gases that are evacuated by the degassing process are directed to the boilers to be combusted. These gases are to be discharged under water to a covered concrete hot well. It is easily deduced that the hot well performs another vital function for the system, that of cooling and condensing the steam. Also, as a side benefit, the water will provide a reasonably effective scrubber which will capture particulate matter and other gases and matter which are soluble. What will become of the water containing the filtrates and soluble contaminates? This water should not be considered simple process water such as that piped through the system as cooling water as it comes in direct contact with the effluent stream and retains significant components of that stream.

Response #6

This permit does not regulate the use of the water from the hotwell. The IDEM, Office of Water Quality has authority to regulate any discharge of a pollutant into regulated bodies of water. Questions about water quality should be directed to IDEM's Office of Water Quality at 1-800-451-6027.

Comment #7

In Condition B.2, please be more specific about the term "mail." It has become a rather generic term these days. Perhaps the addition of a parenthetical (USPS) would suffice.

Response #7

40 CFR 124.20 (d) states "Whenever a party or interested person has the right or is required to act within a prescribed period after the service of notice or other paper upon him or her by mail, 3 days shall be added to the prescribed time. Neither 40 CFR 124.2 nor 40 CFR 124.41 include a definition for "mail." However, since IDEM intends to provide notice of this permit by U.S. postal mail, IDEM agrees to change the condition to reference "U.S. postal mail."

B.2 Effective Date of the Permit [40CFR 124]

Pursuant to 40 CFR 124.15, 40 CFR 124.19, and 40 CFR 124.20, the effective date of this permit will be thirty (30) days after the service of notice of the decision, except as provided in 40 CFR 124. Three (3) days shall be added to the thirty (30) day period if service of notice is by **U.S. postal** mail.

Comment #8

The application has "Part 70" in its title, but Condition B.4(e) starts with "In the event that the Part 70 application is being processed at the same time as this application..." This boilerplate section must be qualified or altered in some way to make it relevant for this specific permit. State what is valid for this permit so that it can be reviewed.

Response #8

Since SDI has not yet submitted a Part 70 permit application, section (e) of Condition B.4 has been deleted, as shown below.

B.4 Significant Source Modification [326 IAC 2-7-10.5(h)]

This document shall also become the approval to operate pursuant to 326 IAC 2-7-10.5(h) when the following requirements are met:

(a) The attached affidavit of construction shall be submitted to the Office of Air Quality (OAQ), Permit Administration & Development Section, verifying that the emission units were constructed as proposed in the application. The emissions units covered in the Significant Source Modification approval may begin operating on the date the affidavit of construction is postmarked or hand delivered to IDEM if constructed as proposed.

(b) If actual construction of the emissions units differs from the construction proposed in the application, the source may not begin operation until the source modification has been revised pursuant to 326 IAC 2-7-11 or 326 IAC 2-7-12 and an Operation Permit Validation Letter is issued.

(c) If construction is completed in phases; i.e., the entire construction is not done continuously, a separate affidavit must be submitted for each phase of construction. Any permit conditions associated with operation start up dates such as stack testing for New Source Performance Standards (NSPS) shall be applicable to each individual phase.

(d) The Permittee shall receive an Operation Permit Validation Letter from the Chief of the Permit Administration & Development Section and attach it to this document.

~~(e) In the event that the Part 70 application is being processed at the same time as this application, the following additional procedures shall be followed for obtaining the right to operate:~~

~~(1) If the Part 70 draft permit has not gone on public notice, then the change/addition covered by the Significant Source Modification will be included in the Part 70 draft.~~

~~(2) If the Part 70 permit has gone through final EPA proposal and would be issued ahead of the Significant Source Modification, the Significant Source Modification will go through a concurrent 45 day EPA review. Then the Significant Source Modification will be incorporated into the final Part 70 permit at the time of issuance.~~

~~(3) If the Part 70 permit has gone through public notice, but has not gone through final EPA review and would be issued after the Significant Source Modification is issued, then the Modification would be added to the proposed Part 70 permit, and the Title V permit will issued after EPA review.~~

Comment #9

Condition B.5 is missing the relevant code cite from its title. Add the cite.

Response #9

The requested change has been made as shown below.

B.5 NSPS Reporting Requirement **[40 CFR 60, Subpart Dc]**

Pursuant to the New Source Performance Standards (NSPS), Part 60, Subpart Dc, the source owner/operator is hereby advised of the requirement to report the following at the appropriate times:

(a) Commencement of construction date (no later than 30 days after such date);

(b) Anticipated start-up date (not more than 60 days or less than 30 days prior to such date); and

(c) Actual start-up date (within 15 days after such date).

Reports are to be sent to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, IN 46206-6015

The application and enforcement of these standards have been delegated to the IDEM, OAQ. The requirements of 40 CFR Part 60 are also federally enforceable.

Comment #10

Condition C.2 (Preventive Maintenance Plan)

Paragraph (a) requires the PMP to be prepared "when operation begins." The language of this requirement should more properly require that the PMP be completed and in place prior to the commencement of operations of the covered equipment for any operational level and shall include the following... This sort of requirement is in keeping with the comment about best practices and good combustion practices.

Under paragraph (a), the caveat paragraph following the list stipulates what the Permittee should do if preparation of the PMP cannot be completed “within the above time frame...” There is no time frame currently specified “above.” A specific time frame must be added above, or included directly in this paragraph.

Suggest the IDEM consider removing the 90 day extension altogether as the need for such an extension would strongly indicate that the Permittee is not ready to operate the emission unit effectively or within any sort of best or good operational practices. Furthermore, the plan includes inspection, maintenance, and repair of emission control and monitoring devices which must be operational at all times when the unit is operated.

Does the IDEM plan to review and approve the PMP?

Under item (d), define “a reasonable time” as it pertains to furnishing records to the Commissioner. Can the Commissioner include expected response with a request? A reasonable time should still be given an upper bound.

Response #10

Paragraph (a) has been changed to clarify that the PMP must be prepared prior to the start of operation of the new emission unit.

Paragraph (a) has been changed to clarify that “within the above time frame” refers to “prior to the start of operation of the new emission unit.”

The allowance for a 90-day extension to prepare the PMP anticipates the possibility that the Permittee could encounter circumstances beyond its control that would necessitate an extension. IDEM does not anticipate that granting a 90-day extension to prepare the PMP would have an adverse effect on emissions, especially given that preventive maintenance is not likely to be necessary during the first 90 days of operation when the unit is new. There are no emission control or emission monitoring devices for this particular emission unit, therefore, the plan would only include preventive maintenance for the vacuum degasser and the natural gas-fired boiler.

The IDEM, OAQ inspector will review the PMPs for the facilities at SDI during his routine inspections of the facility. The inspector plans to prioritize his review of the PMPs in order to concentrate more fully on the major emitting units at the plant, rather than the minor emitting units, such as this proposed vacuum degasser and natural gas-fired boiler. However, if IDEM notices any potential violations or problems with emissions from the unit that could be resolved by improved preventive maintenance, IDEM will exercise its authority to require the Permittee to revise the PMP as necessary to resolve the problem.

Paragraph (d) requires the Permittee to furnish records “within a reasonable time” if requested by the Commissioner pursuant to 326 IAC 2-7-5(13)(C). It is not feasible to define “a reasonable time” in the permit condition because the amount of time that is reasonable would likely depend on many factors, such as the amount of records requested, the age of the records, and the reason for requesting the records. When requesting specific records, IDEM can specify a time it believes is reasonable for providing the records.

Changes to the condition as a result of this comment are shown below.

C.2 Preventive Maintenance Plan [326 IAC 2-7-5(1),(3) and (13)] [326 IAC 2-7-6(1) and (6)] [326 IAC 1-6-3]

(a) If required by specific condition(s) in Section D of this permit, the Permittee shall prepare and maintain a Preventive Maintenance Plan (PMP) ~~when operation begins~~**. The PMP**

shall be prepared prior to the start of operation of the emission unit listed in this permit, and shall include ~~including~~ the following information:

(1) Identification of the individual(s) responsible for inspecting, maintaining, and repairing emission control devices;

(2) A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions; and

(3) Identification and quantification of the replacement parts that will be maintained in inventory for quick replacement.

If, due to circumstances beyond the Permittee's control, the PMP cannot be prepared and maintained ~~within the above time frame~~ **prior to the start of operation of the emission unit listed in this permit**, the Permittee may extend the date an additional ninety (90) days provided the Permittee notifies:

Indiana Department of Environmental Management
Compliance Branch, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

The PMP and the PMP extension notification do not require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(b) The Permittee shall implement the PMP as necessary to ensure that failure to implement a PMP does not cause or contribute to a violation of any limitation on emissions or potential to emit.

(c) A copy of the PMP shall be submitted to IDEM, OAQ, upon request and within a reasonable time, and shall be subject to review and approval by IDEM, OAQ. IDEM, OAQ, may require the Permittee to revise its PMP whenever lack of proper maintenance causes or contributes to any violation. The PMP does not require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(d) Records of preventive maintenance shall be retained for a period of at least five (5) years. These records shall be kept at the source location for a minimum of three (3) years. The records may be stored elsewhere for the remaining two (2) years as long as they are available upon request. If the Commissioner makes a request for records to the Permittee, the Permittee shall furnish the records to the Commissioner within a reasonable time.

Comment #11

In Condition D.1.1(a), last line, shouldn't the limit be expressed with an "or" and then read, "...Btu of heat input or 0.318 pound per hour." Isn't it correct that each of the stated limits is valid in it's own right. Exceeding either limit would be considered a violation.

Response #11

This permit condition expresses the limits the source must meet to be in compliance with the permit. The unit must comply with <u>both</u> limits. Exceeding either limit would be considered a violation of the permit. The limit is written correctly because it states that the unit must comply with the limit in pounds per million Btu <u>and</u> the limit in pounds per hour. No change to the permit is necessary.

Comment #12

In Condition D.1.1(b), the hourly limit has been omitted. Include the hourly limit.

Response #12

Condition D.1.1(b) is the limit established by 326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating). This rule only establishes particulate matter limits in pounds per million Btu of heat input; therefore, IDEM cannot add a pound per hour limit citing this rule as the authority.

Condition D.1.1(a) includes the PM/PM10 BACT limit pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)). The BACT limit is specified in both pounds per million Btu of heat input and in pounds per hour. Additionally, these limits are more stringent than the limit in Condition D.1.1(b), established by 326 IAC 6-2-4.

Comment #13

Conditions D.1.2 and D.1.3 include language that explains that the limits should be followed unless they are changed. The caveat cited in these conditions begs the question of whether there is any limit that the department would consider enforceable and whether or not the department would continue to adjust this condition as needed to keep the applicant within compliance. The language, quoted below, beginning with the word "unless" should not be included within the conditions.

> "...unless these limits are adjusted as follows. If the stack test required under Condition D.1.8 shows that these NOx limits are not achievable in practice for the vacuum degasser boiler, the Department may revise the permit to adjust these NOx limitations. If the stack test required under Condition D.1.8 shows that more stringent NOx limits are achievable, the Department may, at its discretion, use the authority under IC 13-15-7-2 to re-open and revise the limit to more closely reflect the actual stack test results. The Department will provide an opportunity for public notice and comment prior to finalizing any permit revision. IC 13-15-7-3 (Revocation or Modification of a Permit: Appeal to Board) shall apply to this permit condition."

With this language included, the requirement is unclear with respect to what limits if any, are to be enforced. Clearly enforceable limits must be unambiguously set within the permit, subsequent modification not withstanding. Therefore, this language must be removed to clearly state the enforceable condition.

Within the language of the condition as quoted above, there is no code reference cited in support of the departments authority to alter the permit conditions in the case where the "limits are not achievable in practice." Remove this language or clearly cite the authority under which the department may take such action.

The department offers IC 13-15-7-2 when stating that it has the authority to "re-open and revise the limit to more closely reflect the actual stack test results." This cite directly addresses the conditions under which the permit may be reopened, revised or revoked, and none of those conditions grant authority based on an arbitrary, as built, or as operated test result for a specific emissions unit. The code is specific about the conditions under which a permit shall be reopened, and none are based on actual stack test results. The code requires the permit to be reopened, revised or revoked in the following cases:

(1) Additional federal requirements become applicable to a source whose permit allows at least three more years of continued operation;
(2) Additional requirements become applicable to the permitted source under the acid rain program; or
(3) The Commissioner or Administrator of the U.S. EPA determines that the permit contains a material mistake or inaccurate statements were made in establishing the emission standards or other terms or conditions of the permit.

Response #13

While CO and NOx emissions from natural gas fired boilers can usually be accurately predicted, it is uncertain in this case what effect (if any) the degassing emissions will have on the emissions from the boiler's stack. SDI and IDEM have been unable to identify any other source operating a degasser with a similar configuration. Since SDI and IDEM cannot be sure of what effect (if any) the degassing emissions would have on the CO and NOx emissions from the boiler, the CO and NOx limits are written with a "re-opener" clause. This will allow IDEM to increase or decrease the CO and NOx limits based on the results of the initial performance test. IDEM also notes that the commenter left out one part of IC 13-15-7-2 which allows IDEM to reopen and revise a permit if the Commissioner determines that the permit must be revised to assure compliance with the applicable federal requirements.

The SDI permit modification is issued under federal PSD delegation and is subject to case law of the Environmental Appeals Board (EAB). The EAB in *In re AES Puerto Rico L.P.* (EAB 1999) upheld the use of adjustable limits where the permitting authority had the intention of adjusting the limits based on subsequent stack test results. The EAB stated that since the permitting authority was faced with some uncertainty as to what emission limit was achievable, the use of an adjustable limit was a reasonable approach. The EAB also referred to a previous case *In re Hadson Power 14,* 4 E.A.D. 258 (EAB 1992) where the Board denied review of an emission limit that involved the first time a control technology was applied to a particular type of coal-fired boiler. The petitioner had objected to the NOx limit being too high, but the permitting authority had included a permit provision that allowed the NOx limit to be adjusted downward after the facility commenced operation. The Hadson Power approach began with a high emission limit and included the potential for downward adjustment. The AES Puerto Rico approach began with a low emission limit and allowed for upward adjustments. Both cases involved a situation where the permitting authority was faced with some uncertainty as to what emission limit was achievable. In both cases, the use of adjustable limits was upheld.

The circumstances involving the NOx and CO BACT limits established by this permit are similar to the ones described in the above-mentioned EAB cases, where the use of adjustable limits was upheld. Therefore, IDEM believes that sufficient case law exists to justify the use of adjustable limits in this permit. Similarly, IDEM believes that the existing case law is sufficient to establish that IDEM has the authority to re-open and adjust the limits as necessary based on the results of the stack test.

In order to clarify that an relaxation of the limits would still be conditioned on an air quality analysis that ensures compliance with the PSD increment and protection of the NAAQS, the following changes have been made to the conditions.

D.1.2 NOx Limitations (PM) [326 IAC 2-2-3]

Pursuant to 326 IAC 2-2-3 (PSD), the NOx emissions from the LVD boiler shall not exceed 0.04 pound per million Btu of heat input and 1.67 pounds per hour, unless these limits are adjusted as follows. If the stack test required under Condition D.1.8 shows that these NOx limits are not achievable in practice for the vacuum degasser boiler, the Department may revise the permit to adjust these NOx limitations. If the stack test required under Condition D.1.8 shows that more stringent NOx limits are achievable, the Department may, at its discretion, use the authority under IC 13-15-7-2 to re-open and revise the limit to more closely reflect the actual stack test results. The Department will provide an opportunity for public notice and comment prior to finalizing any permit revision. IC 13-15-7-3 (Revocation or Modification of a Permit: Appeal to Board) shall apply to this permit condition. **Any relaxation of the emission limit will require an air quality analysis that ensures protection of the NAAQS and compliance with the PSD increment.**

D.1.3 CO Limitations (PM) [326 IAC 2-2-3]

Pursuant to 326 IAC 2-2-3 (PSD), the CO emissions from the LVD boiler shall not exceed 0.084 pound per million Btu of heat input and 3.51 pounds per hour, unless these limits are adjusted as follows. If the stack test required under Condition D.1.8 shows that these CO limits are not achievable in practice for the vacuum degasser boiler, the Department may revise the permit to adjust these CO limitations. If the stack test required under Condition D.1.8 shows that more stringent CO limits are achievable, the Department may, at its discretion, use the authority under IC 13-15-7-2 to re-open and revise the limit to more closely reflect the actual stack test results. The Department will provide an opportunity for public notice and comment prior to finalizing any permit revision. IC 13-15-7-3 (Revocation or Modification of a Permit: Appeal to Board) shall apply to this permit condition. **Any relaxation of the emission limit will require an air quality analysis that ensures protection of the NAAQS and compliance with the PSD increment.**

Comment #14

Condition D.1.6(d) (Operating Parameters) reads "Combustion emissions shall be reduced through the use of good combustion practices." While I agree in concept, this condition, as stated is not enforceable as stated. How are "good combustion practices" established, maintained, and monitored? How will we know if they are not good? Many commercial and other standards require the use of "best practices," but even then, there must be some reference to the process by which those "best practices" are established and maintained. These "best practices" are usually established in accordance with an approved process. Please provide additional guidance for the applicant and for the public to answer the issue of enforceability.

Response #14

The Permittee must operate using good combustion practices, which means they must follow the manufacturer's specifications and instructions for operating the equipment. Excess emissions would indicate that the equipment is not operating properly. The inspector will check for visible emissions during the routine inspections of the source. The source must also conduct stack testing to show compliance with the emission limits.

Comment #15

Condition D.1.7 (Preventive Maintenance Plan) contains no indication of a time table for the creation of the plan, or its approval cycle. The condition states, "A Preventive Maintenance Plan, in accordance with Section B - Preventive Maintenance Plan, or this permit is required for the LVD boiler." Additional specificity must be included in this permit.

(a) The condition is not enforceable without a requirement for performance. Include a time table for the creation of the plan, and/or its approval cycle as part of the requirement to provide for reasonable enforceability.

(b) Section B of this permit contains no such references to a Preventive Maintenance Plan. Correct the reference (is it in Section C, perhaps) and/or add the missing information.

Response #15

The condition erroneously refers to Section B - Preventive Maintenance Plan. It should refer to Section C - Preventive Maintenance Plan. Condition C.2 of the permit includes the detailed requirements of the PMP, including the necessary contents, the time table for preparing it, and the approval cycle. Therefore, it is not necessary to repeat this information in Condition D.1.7. The condition has been changed as shown below.

D.1.7 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan, in accordance with Section ~~B~~ **C** - Preventive Maintenance Plan, of this permit, is required for the LVD boiler.

Comment #16

In Condition D.1.9, change "natural gas or propane..." to read "...natural gas and/or propane..."

Response #16

The Permittee is required to keep records of the amount of each type of fuel used in the boiler each day of operation. To clarify this, the condition has been changed as shown below.

D.1.9 Record Keeping Requirements [40 CFR 60, Subpart Dc]

(a) Pursuant to 40 CFR 60, Subpart Dc, the Permittee shall maintain records of the amount of ~~natural gas or propane~~ **each type of fuel** combusted in the LVD boiler each day.

Comment #17

The enforcement issue on page 2 of the TSD states

> "On February 15, 2001, EPA issued a notice of violation to Steel Dynamics, Inc. for allegedly beginning construction prior to the effective date of the PSD permit. This enforcement action is unrelated to the proposed modification."

The notice does not address the issue as an allegation, but rather as a finding of fact and finding of violation. This enforcement action is related to this proposed modification by the fact that it is an action taken against the applicant at the same location and this permit is also a preconstruction permit and the applicant may not begin construction on the subject emission unit until after it becomes effective. This statement must be corrected to accurately reflect the facts. The first paragraph of the NOV states, "U.S. EPA finds that Steel Dynamics, Inc. (SDI) is violating..." Page 3, under the heading of Finding of Violation, item 12 states, "SDI has violated..."

Response #17

The TSD should have stated that "EPA is pursuing an enforcement action against the Steel Dynamics Columbia City plant because the EPA alleges that SDI began construction prior to receiving their final permit." The facts of the case are still being investigated and reviewed by the EPA. The enforcement case has not yet been resolved; therefore, IDEM cannot state with any certainty that a violation did occur.

IDEM prefers to have the TSD document the reasoning for the public noticed version of the permit. This addendum to the TSD explains any changes to the permit after public notice. This method provides documentation for each step in the permit process. As a result, IDEM does not make changes to the TSD after public notice.

Comment #18

Formally request the IDEM expeditiously inform all commenters of record, or minimally, those that make a similar request as this, in the event that any comment received for this permit seeks to relax any of the requirements of the permit that has been submitted for public review, especially in the case where the department's initial reaction is to consider granting such a request. Interested parties should be afforded an opportunity to consider such changes.

Response #18

IDEM has not received any comments requesting to relax any of the requirements of this permit. Regardless, a copy of the comments IDEM received from SDI has been sent to the commenter. Additionally, all public comments received on the permit are public records. Anyone may make a formal request to receive copies of any such records.

On April 11, 2002, Stephen A. Loeschner, submitted written comments on the proposed significant source modification to the Part 70 permit. A summary of the comments is as follows.

Comment #1

SDI's activities are within the 40 CFR 52.21(b)(1)(i)(a) list which invokes BACT to control SO_2 at 100 tons per year. PSD permit 183-10097-00030 gives rise to some 222 tons per year of SO_2. Because SDI is not built yet, the boiler is an emission unit within that source and the boiler's size is not an issue. SO_2 BACT for the boiler is obligated which result in permit conditions that then must be federally enforceable on a more or less continuous basis.

IDEM has placed SO_2 pollutant emissions in lbs/ton and lbs/hr in Condition D.1.5 in the draft permit. However those limits are not federally enforceable. The combination of the various conditions D.1.8 through D.1.10 simply cannot lead a reasonable person to believe that IDEM attempted to impose federal enforceability for SO_2. While the boiler emission unit is small in comparison with the entire SDI source, there is still an obligation to have federal enforceability. While the USC and CFR are somewhat lacking regarding the specifics of discretion that IDEM may apply to the case, the EPA published an October 1990 draft NSR Workshop Manual which has been held in rather high regard by the EAB. On page H.6 of the manual it states "where continuous, quantitative measurements [of the regulated pollutant] are infeasible, surrogate parameters **must** be expressed in the permit" (emphasis added). The manual mentions such surrogacy on page H.4, Table H.1; page H.6 middle paragraph; and pages H.7, H.8, H.10, I.3, I.4, and I.6.

SO_2 continuous emission monitoring (CEM) is very well-developed, but its use on such small emission units is burdensome in cost. Most, perhaps in excess of 80% of the SO_2 emissions are expected to be as a result of the sulfur content of the fuel. The expected weight of the SO_2 will likely be in excess of, but close to, twice the weight of the fuel sulfur. As with CEM, continuous fuel sulfur testing is excessively burdensome in cost. Yet the obligation of federal enforceability in accordance with the manual remains.

Therefore:

Prior to permit issuance, conditions must be added to require monthly testing and recording of the natural gas fuel sulfur content by the use of the American Society for Testing and Materials (ASTM) Methods. IDEM should maintain a copy of those ASTM methods in its public file room. Those methods must be incorporated into the permit by reference along with the caveat that the applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the EPA and IDEM. SDI, a service contractor retained by SDI, the fuel vendor, or any other qualified agency may perform the monthly tests. The test results must be submitted to IDEM as quarterly reports, such that they become <u>public</u> records, unlike records maintained by polluters that may be inspected by IDEM–public access to such often being denied.

SDI may object to that requirement as being burdensome for such a small emission unit. And that claim would be valid if the LVD was the only emission unit. However the SDI natural gas usage capability may exceed 5.0 trillion Btu per year, and a single monthly natural gas sulfur test and record is valuable in terms of the data, is economical in terms of cost of data, and is thus appropriate.

What is the "as to be built" capability of SDI to consume natural gas in terms of trillion Btu per year to at least two significant digits?

With the proper implementation of the monthly natural gas sulfur test and record, a once every 2 year SO_2 stack test of the LVD stack would serve well to assure SO_2 federal enforceability.

Response #1

The SO_2 potential to emit (PTE) from the boiler is 0.1 ton per year. Therefore, the boiler has a very small contribution to the SO_2 emissions from the entire source. IDEM has considered the following information regarding the monitoring requirements:

1. The boiler will use natural gas as fuel, which is considered a clean fuel.

2. US EPA has defined natural gas as "…. a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 1.0 grain or less of hydrogen sulfide per 100 standard cubic feet and the hydrogen sulfide constitutes more than 50% (by weight) of the total sulfur in the gas fuel. Additionally, natural gas must either be composed of at least 70% methane by volume or have a gross calorific value between 950 and 1100 Btu per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal- derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value."[1]

3. Based on the above definition, the sulfur content in the "natural gas" will constantly be less than 2.0 grains per 100 standard cubic feet.

4. The SO_2 emissions from the combustion of natural gas are calculated based on an emission factor. The AP-42[2], documents the emission factor of 0.6 lb/MMCF of natural gas burned at the sulfur content of 2 grains per 100 cubic feet of natural gas. It also assumes 100% conversion of fuel sulfur to the SO_2. The emission factor rating is A, which means the quality of the emission factor is excellent. AP-42 states that this quality rating means that the factor was developed from A- and B-rated source test data taken from many randomly chosen facilities in the industry population and that the source category population is sufficiently specific to minimize variability.

5. The PTE of SO_2 emissions from the boiler is 0.1 ton per year, which was calculated using the above worst-case emission factor.

6. The SO_2 emissions are unlikely to increase significantly due to any variations in the fuel sulfur content.

For these reasons, IDEM has determined that fuel sulfur monitoring is not necessary.

The maximum capability of SDI to consume natural gas is shown in the table below.

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[1] See 40 CFR 72.2 Subpart A "Acid Rain Program General Provisions: Definitions", revised as of July 1, 2001.

[2] See Chapter 1.4 Table 1.4-2, "Compilation of Air Pollutant Emission Factors: Natural Gas Combustion", July 1998.

Emission Unit	Heat Input Capacity (MMBtu/hr)
four ladle preheaters (10 MMBtu/hr each)	40
ladle dryer	10
tundish nozzle preheater	10
two tundish preheaters (5 MMBtu/hr each)	10
tundish dryer	5
reheat furnace	260
vacuum degasser boiler	41.8
Total for all units	376.8

Note: The amounts shown in the table do not take into account any permit limits on the amount of natural gas usage.

Due to the small potential to emit of SO_2 from the proposed vacuum degasser boiler, and the fact that SO_2 emissions are not likely to vary significantly, SO_2 stack testing is not being required by this permit.

Comment #2

Hexane - A perpetual HAP myth
The EPA August 21, 2001 Sims Roy CT Hazardous Air Pollutant ("HAP") memo ("Roy") mentions that roughly two-thirds of the total HAP emission mass from natural gas fueled CT's is formaldehyde ("H_2CO"). While the air to fuel ratio, pressure, and temperature of natural gas fired boilers is different from that of CT's, one chemical reaction attribute should be evident by intuition. It is flat out not possible for the components to reassemble (or be present and pass through un-reacted) such that more mixed isomer (or perhaps the n-hexane isomer only?) 6-carbon hexane (containing no oxygen) of molecular weight 86 is emitted than 1-carbon H_2CO of molecular weight 30. Yet USEPA AP-42 Table 1.4-3 (July 1998) indicates a mass ratio of 1.8 / 0.075- a staggering domination by hexane by a mass factor of 24. In the Addendum to the Technical Support Document ("ATSD, TSD"), please purge all references indicating that hexane is anywhere near H_2CO as duct burner and boiler natural gas combustion effluent. Educate the IDEM permit writers that Emission Factor Rating "E" generally means ersatz (used to indicate inferior quality). Part of the reason for that rating is the fact that among the thousands of natural gas fired boilers, there were an abysmal two n-hexane tests (pdf p.27, EPA AP-42 Chapter 1 Section 4 Background Document incorporated herein by reference) and there were zero (0) acetaldehyde tests. I am considerably aggrieved that n-hexane has appeared in 15170 (and that acetaldehyde has not) following my draft permit n-hexane comments in re General Motors Allen County 003- 12830- 00036 on January 2, 2001, in re Cogentrix Lawrence County 093-12432-00021 ("12432") June 5, 2001, in re Mount Vernon Energy 029-12750-00016 on October 19, 2001 and November 13, 2001, and in re Parkview 003-11993-00272 on January 19, 2002, all of which are incorporated herein by reference.

IDEM seems to have no shame in misleading the People, as it wrote on page 19 of the 12432 ATSD October 5, 2001 in response to comment:

"Formaldehyde is not the largest HAP."

It is repugnant that 12 men walked on the moon decades ago and yet the People cannot get a simple accurate answer in re combustion products today.

The U.S. Environmental Protection Agency ("EPA") August 21, 2001 Sims Roy CT Hazardous Air Pollutant ("HAP") memo ("Roy") mentions that roughly two-thirds of the total HAP emission mass from natural gas fueled CT's is formaldehyde ("H_2CO") (third para. under Oxidation Catalyst Systems heading).

EPA emission factors compilation AP-42 para. 3.1.3.5 (April 2000) mentions that roughly two-thirds of the total HAP emission mass from natural gas fueled CT's is H_2CO.

If IDEM does not have one or more peer-reviewed chemical tests of "pipeline quality" natural gas combustion effluent from a boiler, where the mass of formaldehyde was found to be less than that of another HAP at the same source at the same time at a time where "normal" operation was claimed; or if IDEM does not have one or more peer- reviewed chemical tests of "pipeline quality" natural gas combustion effluent from a CT or boiler, where a greater mass of mixed hexane isomers than acetaldehyde was found at the same source at the same time at a time where "normal" operation was claimed; then, the time is now for IDEM to renounce its hexane allegations.

Response #2

There is limited information available about the emissions of Hazardous Air Pollutants (HAPs) from the boiler. The OAQ relies on various sources of information to estimate HAPs emissions to determine applicability of various rules to the projects. The emission factors documented in AP-42 were used to estimate HAPs emissions from the boiler. The AP-42 Chapter 3, table 3.1-3 April/00 version documents the formaldehyde emissions as the largest HAP component from the exhaust of Natural Gas fired turbines. The formaldehyde emissions are at 0.00071 pounds per MMBtu of heat input. The hexane is not listed in this table. The emission rate for formaldehyde is nearly five times greater than the next HAP toluene at 0.00013 pounds per MMBtu.

The hexane emissions were calculated based on AP-42 emission factors for natural gas combustion documented in Table 1.4-2, 1.4-3 and 1.4-4 (July 1998). During the review of a permit application, the OAQ, IDEM researches all information however insignificant, which can help quantify the emissions. The OAQ, concurs with the commenter that rating for the Hexane emission factor is "E" in AP-42 in the above chapter.

As stated in the addendum to the TSD for General Motors permit, the OAQ, IDEM had stated "AP-42 is generally considered to provide a conservative estimate of source emissions in lieu of actual stack test data. The OAQ, IDEM believes that use of these emission factors is sufficient to protect the public health and ensure compliance with both Federal and State air regulations. The introduction to AP-42 states that these factors are 'assumed to be representative of long term averages', such as those utilized to determine PSD applicability.

It is beyond the scope of the OAQ permitting process to re-evaluate the scientific basis of a particular emission factor unless OAQ has specific reservations regarding the factor. The OAQ has no such reservations regarding use of the AP-42 factors for natural gas combustion."

Even moderate increases in these emission factors would not increase the potential to emit HAPs to an amount that would trigger the applicability of 326 IAC 2-4.1-1 (New Source Toxics Control) or any other rule that would establish limits on these HAPs. No changes are made to the permit.

On March 18, 2002, Val Vorndran, submitted written comments on the proposed significant source modification to the Part 70 permit. A summary of the comments is as follows.

Comment #1

Does this mean that SDI already has a permit in place, and now they want to modify this in order to allow for more pollutants? They are not even up and running yet.

Response #1

Steel Dynamics was issued a permit to construct a new steel beam mill on July 7, 1999. A modification to the permit was issued on January 10, 2001. On December 18, 2001, Steel Dynamics applied for this permit to install and operate a new vacuum degasser boiler. SDI applied for this permit only after learning that potential new customers required steel rails with specifications that would require the use of the vacuum degassing process. Since none of the plant operations have begun operating, and construction of the new plant has not yet been completed, IDEM reviewed this application as though it were part of the original permit application to construct the entire plant. The emissions from the new vacuum degasser boiler alone are not in excess of the PSD significance levels; therefore, if the vacuum degasser boiler had been permitted separately, it would not have been required to comply with the requirements of PSD. For administrative purposes, IDEM issued a separate permit document to SDI for the vacuum degasser boiler. However, PSD applicability was based on the combined emissions from the proposed vacuum degasser boiler and the emissions from the rest of the plant processes.

Comment #2

Please tell me exactly what are NOx, CO, VOC, PM/PM10, and SO_2? What dangers to they possess? If my family and myself are exposed to these toxins what are the physical damages? Cancer? Liver disease? Asthma? Kidney failure? Learning disorders? Etc..... Please tell me.

Response #2

CO is carbon monoxide. VOCs are volatile organic compounds. PM is particulate matter (basically dust). PM10 is particulate matter that is less than ten microns in size. SO_2 is sulfur dioxide. The EPA website at http://www.epa.gov/air/urbanair/6poll.html provides more detailed information about the health effects of these pollutants, and the reasons why they are regulated.

The air quality analyses conducted demonstrate that air quality in the vicinity of the plant will continue to comply with the air quality standards. No significant impact on public health or welfare is expected to occur as a result of the emissions from the proposed facility.

Comment #3

My last concern is related to their plant in Butler, Indiana. I would like to know exactly how many times the Butler plant has been in violation of its air permit. Because I think that this should be taken into consideration before issuing them a permit at their Whitley County site. I know that once a plant this size is up and running it is very hard to keep track of its outputs. Both air and ground water contamination. I don't want my life or my family's lives shortened because your air permit was not strict enough. Please hold true to your motto, "We make Indiana a cleaner, healthier place to live."

Response #3

On July 17, 1996 Steel Dynamics, Inc., located at 4500 County Road 59, Butler, Indiana, conducted emissions tests at the EAF baghouse. The results from these tests indicated exceedances of the permitted limits for NOx, SO_2, and VOCs as specified in construction permit 033-3692, operation conditions No. 10, 13, and 12. On September 19 and 20, 1996, the source was retested at the EAF baghouse. The results from these tests indicated exceedances of the permitted limits for NOx, SO_2, and PM10 as specified in construction permit 033-3692, operation conditions No. 10, 13, 5, and 7. IDEM issued a Notice of Violation to SDI on May 22, 1997. The enforcement case has since been resolved through an agreed order which became effective on March 22, 2000. Subsequent stack tests indicated compliance with the emission limits. EPA is also pursuing an enforcement case against the source for the exceedances.

On February 28, 2001, IDEM issued a Notice of Violation to SDI for failure to operate the continuous opacity monitor on the EAF baghouse for approximately 3.25% of the third operating quarter of 1999.

The enforcement case has since been resolved through an agreed order which became effective on April 27, 2001.

On April 12, 2002, IDEM issued a Notice of Violation to SDI alleging a violation of 326 IAC 3 for failure to operate the continuous opacity monitor for 7.46% of the second quarter of 2001. This case is still pending.

IDEM does not have specific authority to deny the permit based on the compliance status of other Steel Dynamics plants at other locations. Additionally, IDEM is not pursuing any enforcement actions against the Steel Dynamics Columbia City plant.

On March 13, 2002, Roland E. Weber, submitted written comments on the proposed significant source modification to the Part 70 permit. A summary of the comments is as follows.

Comment #1

I am interested in the outcome of this matter as well as future proceedings. I would therefore request that I receive such notices.

Response #1

IDEM has added the commenter to the mailing list to receive notices of permitting actions related to this plant.

Comment #2

I recognize that at issue at this point is just compliance with a permit. Your disclaimer aptly states that you have no jurisdiction in specifying and implementing requirements for zoning, odor, or noise. For such issues, you suggest contacting local officials. Just who would such local officials be?

Response #2

For zoning issues, the commenter should contact the local zoning board. For issues with noise or odor, please contact the local health department.

On March 18, 2002, Joseph F. O'Hara, submitted written comments on the proposed significant source modification to the Part 70 permit. A summary of the comments is as follows.

Comment #1

Kindly continue further notice of future proceedings to Joseph F. O'Hara, 6702 Quail Ridge Lane, Fort Wayne, IN 46804.

Response #1

IDEM has added the commenter to the mailing list to receive notices of permitting actions related to this plant.

On April 17, 2002, Tom Davis, submitted oral comments at a public hearing, regarding the proposed significant source modification to the Part 70 permit. A summary of the comments is as follows.

Comment #1

What types of particulate matter control were analyzed? Did you analyze the possibility of venting the emissions through the meltshop baghouse?

Response #1

The maximum potential to emit particulate matter from the proposed uncontrolled vacuum degasser boiler is 0.318 pound per hour, which is equivalent to an outlet grain loading of 0.0035 grains per dry standard cubic foot per minute (gr/dscf). SDI's permit #183-12692-00030 issued January 10, 2001, established particulate matter limits for the meltshop baghouse. The limits are 0.0018 gr/dscf for filterable particulate and 0.0052 gr/dscf for total particulate. Since the outlet particulate grain loading of the baghouse is greater than the outlet grain loading of the uncontrolled vacuum degasser boiler, venting the vacuum degasser boiler to the meltshop baghouse would not succeed in reducing particulate emissions. More likely, the increased air flow to the baghouse would only make the baghouse less efficient in controlling the particulate emissions from the other units in the meltshop. Additionally, IDEM is not aware of any other facility using a baghouse to control particulate emissions from a natural gas-fired boiler.

Comment #2

Has IDEM conducted an inspection of the SDI Columbia City plant? Will there be a complete inspection done prior to the issuance of the proposed permit? With SDI's past track record, I believe it would be an excellent idea to conduct an inspection to determine whether there had been any preconstruction activity that's not allowed prior to the issuance of the permit. Additionally, if an inspection is conducted, I would request that we get a copy of the report prior to the issuance of the permit.

Response #2

On May 1, 2002, Jennifer Dorn, an IDEM inspector conducted an inspection of the Whitley County SDI facility. The inspector found no evidence that the Permittee had begun any construction on the vacuum degasser or the boiler.

On April 17, 2002, Jamie Wesseler, president of Citizens Organized Watch (COW), submitted oral comments at a public hearing, regarding the proposed significant source modification to the Part 70 permit. A summary of the comments is as follows.

Comment #1

I'm concerned that preconstruction activities are going on at the site. I find that just a drive-by inspection is appalling by the IDEM. If you want to see what's going on at the site, you must get out of your vehicle and go in and inspect. I request to have some evidence for the communities that surround the facility. I would ask you to go out and do what you need to do, and that is enforce the law, and give us back information as to what you find. I hate to have to ask the EPA to come in and do something along this line and nature, and we hope that our own Department of Environmental Management would watch after our welfare as much as they've apparently watched after this particular source. We expect you folks to make sure that this organization is within the letter of the law and you are those who have to enforce it. We would like to have regular updates as to how often that is to occur and that you perform those inspections and the results of those inspections so we don't have to take other measures to ensure our health, safety, and welfare of our families.

Response #1

Any time an inspector drives by a source and checks for visible emissions or evidence of some preconstruction activity without entering the actual plant, the inspector completes a form noting that he completed surveillance of the facility without entering the plant site. IDEM is not claiming that these drive-by surveillances substitute for actual inspections, nor is IDEM claiming that these surveillances were intended to find out if SDI had begun preconstruction activities on the vacuum degasser boiler which is to be located inside the meltshop. As of the date of the public hearing, IDEM had not performed a full inspection of the site to check for preconstruction activity of the vacuum degasser boiler because there was no evidence to suggest that such activities had taken place. Additionally, IDEM inspectors must prioritize their workloads, based on the potential environmental effects of the sources they are assigned to inspect. Since this plant has not yet begun operating, the IDEM inspector had not done a full inspection of the plant as of the date of the public hearing. However, at the requests of many of the citizens who attended the public hearing, IDEM agreed to conduct an inspection of the Whitley County SDI plant to check for evidence of preconstruction activity on the vacuum degasser boiler. On May 1, 2002, Jennifer Dorn, an IDEM inspector conducted an inspection of the Whitley County SDI facility. The inspector found no evidence that the Permittee had begun any construction on the vacuum degasser or the boiler.

On April 17, 2002, Charles Acheson, submitted oral comments at a public hearing, regarding the proposed significant source modification to the Part 70 permit. A summary of the comments is as follows.

Comment #1

What happens with the dust from the baghouse? How is it treated and where does it go? Does it go to a hazmat site?

Response #1

There is no baghouse controlling the vacuum degasser boiler. IDEM presumes the commenter is referring to the meltshop baghouse, which was previously permitted under 183-10097. The air permit does not regulate the disposal of the dust after it is collected by the baghouse. The EPA and IDEM's Office of Land Quality regulate the disposal of the meltshop baghouse dust. SDI has indicated that the meltshop baghouse dust is a listed hazardous waste and that it is properly disposed of off-site.

Comment #2

My other question has to do with the hotwell. You will have some solids there. What becomes of that? What kind of material is that? Is it hazardous? Is that introduced back into the burner?

Response #2

Gases from the vacuum degasser will pass through a hotwell, then exhaust directly to the natural gas-fired boiler. The hotwell is a large covered concrete container of water. The degassing process itself is not expected to generate any additional particulate matter at the LMF. However the vacuum created by the degasser may collect a small amount of the particulate matter generated by the LMF. Because the hotwell acts as a scrubber, the particulate matter, if any, that is collected by the vacuum degasser would be caught in the hotwell and not exhausted from the degasser itself. Further, any exhaust through the boiler stack must meet the limits in Condition D.1.1. Particulate matter will not be introduced back into the boiler. Any significant amount of particulate matter introduced into the boiler would cause operational problems with the boiler.

This permit does not regulate the use of the water from the hotwell. The IDEM, Office of Water Quality has authority to regulate any discharge of a pollutant into regulated bodies of water. Questions about water quality should be directed to IDEM's Office of Water Quality at 1-800-451-6027.

On April 16, 2002, David Hatchett of Baker Daniels, on behalf of SDI, submitted written comments regarding the proposed significant source modification to the Part 70 permit. A summary of the comments is as follows.

Comment #1

Please revise the description of the boiler in Section A.2 and D.1 to indicate that 41.8 MMBtu/hr is the nominal capacity of the boiler. Heat input values on pieces of equipment are engineering design numbers and do not necessarily reflect a particular unit's precise performance under varying operating conditions. Thus, "nominal" should be inserted in the description.

Response #1

IDEM has changed the description as shown below. The change has been made in Sections A.2 and D.1 of the permit.

> one (1) new ladle vacuum degasser (LVD) with a nominal maximum capacity of 200 tons per hour of steel and one (1) new boiler to power the LVD. Gases from the LVD will be directed to the new boiler for combustion in the boiler. The boiler has a **nominal** maximum heat input capacity of 41.8 MMBtu per hour, and will use natural gas as the primary fuel, with propane used as an emergency back up fuel. Emissions from the boiler will exhaust through stack 40.

Comment #2

In Condition C.6(c), the two references to OAM should be changed to OAQ.

Response #2

The requested change has been made.

Comment #3

Because only one PMP is required by this permit, SDI requests that Condition C.11(e) reference Preventive Maintenance Plan (singular).

Response #3

The requested change has been made.

Comment #4

Condition C.13(b) appears to be written for an already-operating Title V source. SDI suggests changes as shown below because the LVD will not necessarily be constructed within ninety (90) days of permit issuance.

> Unless otherwise specified in this permit, all record keeping requirements not already legally required shall be implemented ~~within ninety (90) days of permit issuance~~ **when operation of the emission unit begins**.

Response #4

IDEM agrees. The requested change has been made as shown above.

Comment #5

In Condition D.1.6(b), please change "...209.0 million cubic feet..." to "...209 million cubic feet..." This change ensures that the measurement of accuracy of the natural gas meter is consistent with the permit limit.

Response #5

The requested change has been made.

Comment #6

In Condition D.1.10, the word "reported" appears twice at the end of the first sentence.

Response #6

The condition has been corrected as shown below.

D.1.10 Reporting Requirements

A quarterly summary of the information to document compliance with Condition D.1.6 (b) and (c) shall be submitted to the address listed in Section C - General Reporting Requirements, of this permit, using the reporting form located at the end of this permit, or its equivalent, not later than thirty (30) days after the end of the quarter being reported. ~~reported.~~ The report submitted by the Permittee does require the certification by the “responsible official” as defined by 326 IAC 2-7-1(34).

Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for a Part 70 Significant Source Modification.

Source Background and Description

Source Name:	**Steel Dynamics, Inc.**
Source Location:	**2601 County Road 700 East, Columbia City, Indiana 46725**
County:	**Whitley**
SIC Code:	**3312**
Operation Permit No.:	**None**
Operation Permit Issuance Date:	**not yet issued**
Significant Source Modification No.:	**183-15170-00030**
Permit Reviewer:	**Nisha Sizemore**

The Office of Air Quality (OAQ) has reviewed a modification application from Steel Dynamics, Inc. relating to the construction of the following emission units and pollution control devices:

(a) one (1) new ladle vacuum degasser (LVD) with a maximum capacity of 200 tons per hour of steel and one (1) new boiler to power the LVD. Gases from the proposed LVD will be directed to the proposed new boiler for combustion in the boiler. The boiler has a maximum heat input capacity of 41.8 MMBtu per hour, and will use natural gas as the primary fuel, with propane used as an emergency back up fuel. Emissions from the boiler will exhaust through stack 40

SDI plans to use the LVD unit during production of rail products, which comprise one of the many structural products to be made at the facility. The boiler will be used to produce steam to power a steam jet ejector vacuum pumping system. The vacuum will be used to draw gases off of the molten steel. The gases include hydrogen, carbon monoxide, carbon dioxide, and nitrogen. Since hydrogen and CO have heating value, the gases drawn off of the steel ladle will be discharged under water to a covered concrete hot well. The gases from the hot well will be vented to the boiler where they will be combusted.

History

On July 7, 1999, Steel Dynamics, Inc. was issued a PSD permit to construct and operate a steel beam mill. The PSD permit was appealed to the Environmental Appeals Board (EAB). On June 22, 2000, the EAB issued an order granting review in part and denying review in part. In response to the remand, IDEM issued a modification 183-12692-00030 to the construction permit on January 10, 2001. On December 18, 2001, Steel Dynamics submitted an application to the OAQ requesting to add a vacuum degasser and a boiler to their steel beam plant. The source has begun construction of the steel beam plant, but has not yet begun operating the plant.

Enforcement Issue

On February 15, 2001, EPA issued a notice of violation to Steel Dynamics, Inc. for allegedly beginning actual construction prior to the effective date of the PSD permit. This enforcement action is unrelated to the proposed modification.

Stack Summary

Stack ID	Operation	Height (feet)	Diameter (feet)	Flow Rate (acfm)	Maximum Temperature (^{0}F)
40	vacuum ladle degasser boiler	40	2.5	18,012	500

Recommendation

The staff recommends to the Commissioner that the Part 70 Significant Source Modification be approved. This recommendation is based on the following facts and conditions:

Unless otherwise stated, information used in this review was derived from the application and additional information submitted by the applicant.

An application for the purposes of this review was received on December 18, 2001. Additional information was received on January 31, 2002.

Emission Calculations

See Appendix A of this document for detailed emissions calculations (6 pages).

Potential To Emit of Modification

Pursuant to 326 IAC 2-1.1-1(16), Potential to Emit is defined as "the maximum capacity of a stationary source to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or type or amount of material combusted, stored, or processed shall be treated as part of its design if the limitation is enforceable by the U. S. EPA."

This table reflects the PTE before controls. Control equipment is not considered federally enforceable until it has been required in a federally enforceable permit.

Pollutant	Potential to Emit from Natural Gas usage (tons/year)	Potential to Emit from Propane Usage (tons/year)	Worst Case Potential To Emit (tons/year)
PM	1.39	1.2	1.39
PM-10	1.39	1.2	1.39
SO_2	0.11	0.01	0.11
VOC	0.48	1.0	1.0
CO	15.38	6.2	15.38
NO_x	7.32	37.0	37.0

HAP's	Potential To Emit (tons/year)
lead	0.000092
mercury	0.000048
beryllium	0.0000022
benzene	0.000384
dichlorobenzene	0.0002197
formaldehyde	0.01373
hexane	0.3296
toluene	0.0006225
cadmium	0.0002014
chromium	0.0002563
manganese	0.00006957
nickel	0.0003845
TOTAL	0.34561017

Justification for Modification

The Part 70 Operating permit is being modified through a Part 70 Significant Source Modification. This modification is being performed pursuant to 326 IAC 2-7-10.5(f)(1), because it is subject to the requirements of 326 IAC 2-2.

County Attainment Status

The source is located in Whitley County.

Pollutant	Status
PM-10	attainment
SO_2	attainment
NO_2	attainment
Ozone	attainment
CO	attainment
Lead	attainment

(a) Volatile organic compounds (VOC) are precursors for the formation of ozone. Therefore, VOC emissions are considered when evaluating the rule applicability relating to the ozone standards. Whitley County has been designated as attainment or unclassifiable for ozone. Therefore, VOC emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2 and 40 CFR 52.21.

(b) Whitley County has been classified as attainment or unclassifiable for all other criteria pollutants. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2 and 40 CFR 52.21.

(c) Fugitive Emissions
Since this type of operation is one of the 28 listed source categories under 326 IAC 2-2 and since there are applicable New Source Performance Standards that were in effect on August 7, 1980, the fugitive PM emissions are counted toward determination of PSD applicability.

Source Status

Existing Source PSD or Emission Offset Definition (emissions after controls, based upon 8760 hours of operation per year at rated capacity and/or as otherwise limited):

Pollutant	Emissions (tons/year)
PM	greater than 100
PM-10	greater than 100
SO_2	greater than 100
VOC	greater than 100
CO	greater than 100
NOx	greater than 100
lead	0.432

(a) This existing source is a major stationary source because an attainment regulated pollutant is emitted at a rate of 100 tons per year or more, and it is one of the 28 listed source categories.

(b) These emissions are based upon previously issued permits CP183-10097 issued July 7, 1999, and Permit Modification 183-12692 issued January 10, 2001.

Potential to Emit of Modification After Issuance

The table below summarizes the potential to emit, reflecting all limits, of the significant emission units after controls. The control equipment is considered federally enforceable only after issuance of this Part 70 source modification.

		Potential to Emit (tons/year)						
Process/facility		PM	PM-10	SO_2	VOC	CO	NO_X	lead
ladle vacuum degasser boiler	natural gas usage (209 MMCF/yr)	0.8	0.8	0.1	0.3	8.8	4.2	0.000052
	propane usage (222 kgal/yr)	0.1	0.1	0.00	0.1	0.4	2.1	0.00
	total	0.9	0.9	0.1	0.4	9.2	6.3	0.000052
all previously permitted facilities at the steel beam plant		greater than 100	greater than 100	greater than 100	greater than 100	greater than 100	greater than 100	0.432
Total		greater than 100	greater than 100	greater than 100	greater than 100	greater than 100	greater than 100	0.432052

Since the plant has not yet begun operation, the potential to emit of the entire plant (not just the proposed new LVD boiler) must be included in the prevention of significant deterioration (PSD) applicability determination. As a result, the installation of the LVD boiler must be reviewed under the requirements of PSD, even though the potential to emit of the LVD boiler by itself, is less than the PSD applicability levels.

Federal Rule Applicability

(a) The LVD boiler is subject to the New Source Performance Standard, 326 IAC 12, (40 CFR 60, Subpart Dc. This rule applies to boilers constructed after June 9, 1989, with rated capacities greater than 10 MMBtu per hour but less than 100 MMBtu per hour. This rule does not include any emission limitations for natural gas or propane-fired boilers. Pursuant to this rule, the source shall maintain records of the amounts of each fuel combusted during each day.

(b) There are no National Emission Standards for Hazardous Air Pollutants (NESHAPs)(326 IAC 14 and 40 CFR Part 61 or Part 63) applicable to this proposed modification.

State Rule Applicability - LVD Boiler

326 IAC 2-2 (Prevention of Significant Deterioration (PSD))

The LVD boiler is subject to the requirements of 326 IAC 2-2 (PSD). The PSD provisions require that this major source be reviewed to ensure compliance with the National Ambient Air Quality Standard (NAAQS), the applicable PSD air quality increments, and the requirements to apply Best Available Control Technology (PSD - Control Technology Review; Requirements) for the affected pollutants.

BACT for the LVD boiler is determined on a case by case basis by reviewing similar process controls and new available technologies. In addition, economic, energy, and environmental impacts are considered in IDEM's final decision. Control technology summaries of the facilities covered in this modification are included in Appendix B of this TSD.

A modeling analysis was conducted to show that the emissions from the source do not violate the NAAQS and do not exceed the incremental consumption above eighty percent (80%) of the PSD increment for any affected pollutant. A description and the results of this analysis are found in Appendix C of this TSD.

326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating)

This rule applies to boilers constructed after September 21, 1983. Pursuant to this rule, the particulate matter emissions from the LVD boiler shall not exceed 0.41 pound per million Btu of heat input. The limit was calculated using the following equation:

$$Pt = \frac{1.09}{Q^{0.26}}$$

where

Pt = pounds of particulate matter emitted per million Btu (lb/MMBtu) heat input.
Q = Total source maximum operating capacity rating in million Btu per hour heat input.
Note: As each new indirect heating facility is added to a plant Q will increase. In this case, since there are no other indirect heating facilities at the plant, Q is equal to the maximum capacity of the LVD boiler, or 41.8 MMBTU/hr.

Compliance Requirements

Permits issued under 326 IAC 2-7 are required to ensure that sources can demonstrate compliance with applicable state and federal rules on a more or less continuous basis. All state and federal rules contain compliance provisions, however, these provisions do not always fulfill the requirement for a more or less continuous demonstration. When this occurs IDEM, OAQ, in conjunction with the source, must develop specific conditions to satisfy 326 IAC 2-7-5. As a result, compliance requirements are divided into two sections: Compliance Determination Requirements and Compliance Monitoring Requirements.

Compliance Determination Requirements in Section D of the permit are those conditions that are found more or less directly within state and federal rules and the violation of which serves as grounds for enforcement action. If these conditions are not sufficient to demonstrate continuous compliance, they will be supplemented with Compliance Monitoring Requirements, also Section D of the permit. Unlike Compliance Determination Requirements, failure to meet Compliance Monitoring conditions would serve as a trigger for corrective actions and not grounds for enforcement action. However, a violation in relation to a compliance monitoring condition will arise through a source's failure to take the appropriate corrective actions within a specific time period.

The compliance monitoring requirements applicable to the LVD boiler are as specified below:

(a) Pursuant to 40 CFR 60, Subpart Dc, the source shall maintain records of the amounts of each fuel combusted during each day.

(b) Not later than 180 days after startup of the LVD boiler, a stack test shall be performed to measure NOx and CO emissions, using methods as approved by the Commissioner.

These monitoring conditions are necessary because the source must demonstrate compliance with 326 IAC 2-2 (PSD), and 40 CFR 60, Subpart Dc.

Conclusion

The construction of this proposed modification shall be subject to the conditions of the attached proposed Part 70 Significant Source Modification No. 183-15170-00030.

vacuum degasser boiler
Potential Emissions

Appendix A: Emissions Calculations
Natural Gas Combustion Only
MM BTU/HR <100
vacuum degasser boiler

Company Name: Steel Dynamics, Inc.
Plant Location: 2601 County Road 700 East, Columbia City, IN
County: Whitley
Permit Reviewer: Nisha Sizemore
Source Modification #: 183-15170
Plt. ID #: 183-00030

Heat Input Capacity MMBtu/hr	Potential Throughput MMCF/yr
41.8	366.2

Pollutant

	PM	PM10	SO2	NOx	VOC	CO
Emission Factor in lb/MMCF	7.6	7.6	0.6	40.0	2.6	84.0
Potential Emission in tons/yr	1.39	1.39	0.11	7.32	0.48	15.38

Methodology

All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
PM emission factors are condensable and filterable.

Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,000 MMBtu

Emission Factors are from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, 1.4-3, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03 (SUPPLEMENT D 3/98)
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton
See page 2 for HAPs emissions calculations.

Appendix A: Emissions Calculations
Natural Gas Combustion Only
MM BTU/HR <100
vacuum degasser boiler
HAPs Emissions

Company Name: Steel Dynamics, Inc.
Plant Location: 2601 County Road 700 East, Columbia City, IN
County: Whitley
Permit Reviewer: Nisha Sizemore
Source Modification #: 183-15170
Plt. ID #: 183-00030

HAPs - Organics

	Benzene	Dichlorobenzene	Formaldehyde	Hexane	Toluene
Emission Factor in lb/MMcf	2.1E-03	1.2E-03	7.5E-02	1.8E+00	3.4E-03
Potential Emission in tons/yr	3.845E-04	2.197E-04	1.373E-02	3.296E-01	6.225E-04

HAPs - Metals

	Lead	Cadmium	Chromium	Manganese	Nickel
Emission Factor in lb/MMcf	5.0E-04	1.1E-03	1.4E-03	3.8E-04	2.1E-03
Potential Emission in tons/yr	9.154E-05	2.014E-04	2.563E-04	6.957E-05	3.845E-04

Methodology is the same as page 1.

The five highest organic and metal HAPs emission factors are provided above.
Additional HAPs emission factors are available in AP-42, Chapter 1.4.

Vacuum degasser boiler
Potential Emissions

Appendix A: Emission Calculations
LPG-Propane - vacuum degasser boiler

Company Name: Steel Dynamics, Inc.
Plant Location: 2601 County Road 700 East, Columbia City, IN
County: Whitley
Permit Reviewer: Nisha Sizemore
Source Modification #: 183-15170
Plt. ID #: 183-00030

Heat Input Capacity MMBtu/hr	Potential Throughput kgals/year	SO2 Emission factor = 0.10 x S; S = Weight % Sulfur = 0.05
41.80	3895.40	Note: Based on 8760 hours per year of operation using propane.

	Pollutant					
	PM	PM10	SO2	NOx	VOC	CO
Emission Factor in lb/kgal	0.6	0.6	0.005 *(0.10S)*	19.0	0.5	3.2
Potential Emission in tons/yr	1.2	1.2	0.0097	37.0	1.0	6.2

Methodology

1 gallon of LPG has a heating value of 94,000 Btu

Potential Throughput (kgals/year) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1kgal per 1000 gallon x 1 gal per 0.094 MMBtu

Emission Factors are from AP42, Fifth Edition (January 1995), Table 1.5-2 (SCC #1-02-010-02)

Emission (tons/yr) = Throughput (kgals/yr) x Emission Factor (lb/kgal) / 2,000 lb/ton

vacuum degasser boiler
Limited Emissions

Appendix A: Emissions Calculations
Natural Gas Combustion Only
MM BTU/HR <100
vacuum degasser boiler

Company Name: Steel Dynamics, Inc.
Plant Location: 2601 County Road 700 East, Columbia City, IN
County: Whitley
Permit Reviewer: Nisha Sizemore
Source Modification #: 183-15170
Plt. ID #: 183-00030

Heat Input Capacity MMBtu/hr	Potential Throughput MMCF/yr	
41.8	209.0	Note: The fuel limit of 209 MMCF/yr is based on 5000 hr/yr of operation.

	Pollutant					
	PM	PM10	SO2	NOx	VOC	CO
Emission Factor in lb/MMCF	7.6	7.6	0.6	40.0	2.6	84.0
Potential Emission in tons/yr	0.8	0.8	0.1	4.2	0.3	8.8

Methodology

All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
PM emission factors are condensable and filterable.

Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,000 MMBtu

Emission Factors are from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, 1.4-3, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03
(SUPPLEMENT D 3/98)
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton
See page 2 for HAPs emissions calculations.

Appendix A: Emissions Calculations
Natural Gas Combustion Only
MM BTU/HR <100
vacuum degasser boiler
HAPs Emissions

Company Name: Steel Dynamics, Inc.
Plant Location: 2601 County Road 700 East, Columbia City, IN
County: Whitley
Permit Reviewer: Nisha Sizemore
Source Modification #: 183-15170
Plt. ID #: 183-00030

HAPs - Organics

	Benzene	Dichlorobenzene	Formaldehyde	Hexane	Toluene
Emission Factor in lb/MMcf	2.1E-03	1.2E-03	7.5E-02	1.8E+00	3.4E-03
Potential Emission in tons/yr	2.195E-04	1.254E-04	7.838E-03	1.881E-01	3.553E-04

HAPs - Metals

	Lead	Cadmium	Chromium	Manganese	Nickel
Emission Factor in lb/MMcf	5.0E-04	1.1E-03	1.4E-03	3.8E-04	2.1E-03
Potential Emission in tons/yr	5.225E-05	1.150E-04	1.463E-04	3.971E-05	2.195E-04

Methodology is the same as page 1.

The five highest organic and metal HAPs emission factors are provided above.
Additional HAPs emission factors are available in AP-42, Chapter 1.4.

Appendix A: Emission Calculations
LPG-Propane - vacuum degasser boiler

Company Name: Steel Dynamics, Inc.
Plant Location: 2601 County Road 700 East, Columbia City, IN
County: Whitley
Permit Reviewer: Nisha Sizemore
Source Modification #: 183-15170
Plt. ID #: 183-00030

Heat Input Capacity MMBtu/hr	Potential Throughput kgals/year	SO2 Emission factor = 0.10 x S
		S = Weight % Sulfur = 0.05
41.80	222.34	Fuel limit is based on 500 hours per year of operation.

	Pollutant					
	PM	PM10	SO2	NOx	VOC	CO
Emission Factor in lb/kgal	0.6	0.6	0.005 *(0.10S)*	19.0	0.5	3.2
Potential Emission in tons/yr	0.1	0.1	0.0006	2.1	0.1	0.4

Methodology

1 gallon of LPG has a heating value of 94,000 Btu

Potential Throughput (kgals/year) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1kgal per 1000 gallon x 1 gal per 0.094 MMBtu

Emission Factors are from AP42, Fifth Edition (January 1995), Table 1.5-2 (SCC #1-02-010-02)

Emission (tons/yr) = Throughput (kgals/yr) x Emission Factor (lb/kgal) / 2,000 lb/ton

Appendix B
BACT Analysis

Source Name:	**Steel Dynamics, Inc.**
Source Location:	**2601 County Road 700 East, Columbia City, Indiana 46725**
County:	**Whitley**
SIC Code:	**3312**
Operation Permit No.:	**None**
Operation Permit Issuance Date:	**not yet issued**
Significant Source Modification No.:	**183-15170-00030**
Permit Reviewer:	**Nisha Sizemore**

The Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ), has performed the following federal BACT review for the proposed ladle vacuum degasser boiler to be owned and operated by Steel Dynamics. The potential to emit of all pollutants from the proposed new unit are estimated to be less than the PSD significance levels; however, since the SDI Whitley plant has not yet begun operation, the PTE of the entire plant (not just the boiler) must be counted toward the applicability determination. The permit for the SDI Whitley plant was reviewed pursuant to the PSD program for PM, PM-10, NO_x, SO_2, VOC, and CO.

The source is located in Whitley County, which is designated as attainment or unclassifiable for all criteria pollutants (VOC, NOX, CO, PM, PM10, $S0_2$ and Lead). Therefore, these pollutants were reviewed pursuant to the PSD Program (326 IAC 2-2 and 40 CFR 52.21). The PM, PM-10, NO_x, SO_2, VOC, and CO emissions are subject to BACT review because the pollutant emissions are above PSD significant threshold levels set forth in 326 IAC 2-2. Even though the PSD applicability is based on the emissions from the entire plant, this permit and corresponding BACT analysis are only for the new emission unit. The BACT determinations which were previously established for existing units at the plant are not being re-evaluated through this permit review.

The BACT determination is an emission limitation based on the maximum degree of reduction for each pollutant subject to regulation under 326 IAC 2-2. In accordance with the "Top-Down" analysis for Best Available Control Technology, with guidance set forth in USEPA 1990 draft New Source Review Workshop Manual, the BACT analysis takes into account the energy, environment, and economic impacts on the source. The emissions reductions may be determined through the application of available control techniques, process design, and/or operational limitations.

Ladle Vacuum Degasser Boiler

SDI proposes to install a new ladle vacuum degasser (LVD) and a new boiler to power the LVD. Gases from the proposed LVD will be directed to a proposed new boiler for combustion in the boiler. The boiler has a maximum heat input capacity of 41.8 MMBtu per hour, and will use natural gas as the primary fuel, with propane used as an emergency back up fuel.

SDI plans to use the LVD unit during production of rail products, which comprise one of the many structural products to be made at the facility. The boiler will be used to produce steam to power a steam jet ejector vacuum pumping system. The vacuum will be used to draw gases off of the molten steel. The gases include hydrogen, carbon monoxide, carbon dioxide, and nitrogen. Since hydrogen and CO have heating value, the gases drawn off of the steel ladle will be discharged under water to a covered concrete hot well. The gases from the hot well will be vented to the boiler where they will be combusted. As such, the only emission point is the vacuum degasser boiler itself. BACT for the boiler is discussed below.

The degassing operation will be a batch process; therefore, the boiler's operation will be highly variable. After an EAF melts the steel, it is tapped and sent to the LMS (in the case of rail) for degassing. The boiler must be ramped up to a sufficient temperature to create a vacuum. The actual degassing of steel is estimated to take from 30 to 60 minutes per batch, during which time the degasser air flow is directed into the boiler. Once the steel degassing is complete, the degasser is disengaged. Depending on how quickly another batch of molten steel is ready to be degassed, the boiler is either ramped down to conserve fuel or kept hot for the next ladle of molten steel.

Since SDI only intends to use the vacuum degasser during production of rail products, it will not be necessary to operate the vacuum degasser at all times. SDI proposes to limit natural gas and propane usages in the vacuum degasser boiler to 209 million cubic feet per year and 222 kilogallons per year, respectively.

(1) PM/PM10

There are three potential sources of filterable emissions from combustion sources: mineral matter found in the fuel, solids or dust in the ambient air used for combustion, and unburned carbon formed by incomplete combustion of the fuel. Due to the fact that natural gas is a gaseous fuel, filterable PM emissions are typically low. Particulate matter from natural gas combustion has both filterable and condensible fractions. The particulate matter generated from natural gas combustion is usually larger molecular weight hydrocarbons that are not fully combusted. Increased PM emissions may result from poor air/fuel mixing or maintenance problems.

There are two sources of condensible particulate emissions from combustion sources: condensible organics that are the result of incomplete combustion and sulfuric acid mist which is found as sulfuric acid dihydrate. For natural gas-fired sources such as the boiler there should be no condensible organics originating from the source because the main components of natural gas (i.e. methane and ethane) are not condensible at the temperatures found in Method 202 ice bath. As such, any condensed organics are from the ambient air. The most likely condensible particulate matter from natural gas combustion sources is the sulfuric acid dihydrate, which results when the sulfur in the fuel and the ambient air is combusted and then cools.

Control Options Evaluated - The following control options were evaluated in the BACT review:

Fabric Filter (Baghouse)
Electrostatic Precipitator (ESP)
Wet Scrubber
Cyclones

Technically Infeasible Control Options - All control options are technically infeasible because the primary fuel for the proposed boiler is natural gas, which has little to no ash that would contribute to the formation of PM or PM10. The particulate concentration in the boiler exhaust gas stream would be too low to be effectively controlled by any of these options. Add-on controls have never been applied to commercial natural gas or propane fired boilers, therefore, add-on particulate matter control equipment is not considered to be proven on this type of facility. Additionally, capital costs for these add-on control options are usually high. The potential particulate emissions from the boiler are very low (less than 1.5 tons per year), which would make these options economically infeasible. No further evaluation of add-on particulate controls is necessary.

(2) NOx

Nitrogen oxide formation during combustion consists of three types, thermal NOx, prompt NOx, and fuel NOx. The principal mechanism of NOx formation in natural gas combustion is thermal NOx. The thermal NOx mechanism occurs through the thermal dissociation and subsequent reaction of nitrogen and oxygen molecules in the combustion air. Most NOx formed through the thermal NOx is affected by three factors: oxygen concentration, peak temperature, and time of exposure at peak temperature. As these factors increase, NOx emission levels increase. The emission trends due to changes in these factors are fairly consistent for all types of natural gas-fired boilers and furnaces. Emission levels vary considerably with the type and size of combustor and with operating conditions (e.g. combustion air temperature, volumetric heat release rate, load, and excess oxygen level). The second mechanism of NOx formation, prompt NOx, occurs through early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NOx reactions occur within the flame and are usually negligible when compared to the amount on NOx formed through the thermal NOx mechanism. The final mechanism of NOx formation, fuel NOx, stems from the evolution and reaction of fuel-bonded nitrogen compounds with oxygen. Due to the characteristically low fuel nitrogen content of natural gas, NOx formation through the fuel NOx mechanism is insignificant.

Control Options Evaluated - The following control options were evaluated in the BACT review:

Selective Catalytic Reduction (SCR)
Selective Noncatalytic reduction (SNCR)
Flue Gas Recirculation (FGR)
Ultra Low NOx Burners
Low NOx Burners

Selective Catalytic Reduction (SCR) introduces a reducing agent into the flue gas, upstream of a catalyst bed, which is maintained at an elevated temperature. The ammonia reacts with NOx formed during combustion to form molecular nitrogen and water. SCR has begun to be used to control emissions from boilers during the last 10 years. The use of SCR on boilers has been demonstrated to be technologically feasible and could therefore be considered if found to be cost effective.

Selective Noncatalytic reduction (SNCR) is a post-combustion process in which a reagent mixture is injected into the elevated temperature flue gas stream. Using urea solution as reagent, a portion of the NOx is converted to nitrogen, water, and carbon dioxide. The process may release ammonia during the incomplete combustion of urea. The operating temperature of SNCR is much higher than the exit gas temperature from the boiler. This temperature difference makes SNCR technically infeasible.

Flue Gas Recirculation (FGR) incorporates the recirculation of a portion of the flue gas back to the primary combustion zone as a replacement for the combustion air. The recirculated combustion products provide inert gases that lower the adiabatic flame temperature and the overall oxygen concentration in the combustion zone. As a result, FGR controls NOx emissions by reducing the generation of thermal NOx. FGR has been demonstrated to be technically feasible for controlling NOx emissions from natural gas-fired boilers. This option could be used if found to be economically feasible.

Low NOx burners and ultra low NOx burners control mixing of fuel and air in a pattern that keeps flame temperature low and dissipates the heat quickly. Low NOx burners incorporate many different design principles to achieve low NOx operation.

Technically feasible control alternatives - The technically feasible control alternatives are ranked in order of effectiveness as follows:

(1) SCR
(2) external FGR
(3) “ultra” low NOx burners
(4) low NOx burners

Implementing SCR would require substantial capital expenditures and additional energy to keep the catalyst bed at high temperature. Baseline NOx emissions are estimated at 4.2 tons per year. The estimated cost effectiveness of using SCR to further reduce NOx emissions is in excess of $20,000 per ton of NOx removed. SCR is considered economically infeasible.

SDI submitted a cost analysis for incorporating external FGR into the boiler design. The cost was based on information from a degassing system vendor. The vendor expressed concern regarding the cyclic demand on the boiler and flame instability from external FGR. The vendor stated that in order to see the benefit of external FGR, the boiler must be in operation for a minimum of thirty minutes. The actual degassing process is only expected to take 30 to 60 minutes, after which the boiler may be ramped down to conserve fuel. The expected fuel penalty for operating the boiler in such a manner to allow for the benefits of the external FGR is estimated to be ten to thirty percent[1]. Regardless, the vendor provided a cost estimate for the use of external FGR. An estimated fifty percent (50%) control efficiency for NOx was used for the purposes of completing the cost analysis. Since NOx emissions without the external FGR system (using only ultra low NOx burners) are only 4.2 tons per year, the external FGR system would only reduce NOx by 2.1 tons per year. External FGR would also reduce CO emissions by approximately forty percent (40%); therefore, this reduction was also taken into account in the cost effectiveness analysis. The annual cost effectiveness of using external FGR is estimated to be in excess of $30,000 per ton of NOx and CO reduced. This cost is not considered feasible.

Ultra low NOx burners, which are sold under various trade names, are based on essentially the same technology as low NOx burners but are refined to achieve even lower NOx levels. The newest generation of burners create internal air recirculation inside the boiler chamber, thus achieving many of the benefits of external FGR without the cost and inefficiency of external FGR. Such burners have been used extensively in natural gas boilers of similar size and are therefore considered to be feasible as a pollution prevention technique for reducing NOx emissions.

(3) SO_2

Sulfur dioxide emissions from natural gas-fired combustion sources are low because pipeline quality gas has a low sulfur content. A properly designed and operated boiler utilizing low sulfur natural gas will insure minimal SO_2 emissions.

Control Options Evaluated - the following control options were evaluated in the BACT review:

Flue Gas Desulfurization System

Discussion - A flue gas desulfurization system (FGD) is comprised of a spray dryer that uses lime as a reagent followed by particulate control or wet scrubber. Lime is injected by a spray dryer into the flue gas in the form of fine droplets under well-controlled conditions such that the droplets will absorb SO_2 from the flue gas and then become dry particulate due to evaporation of water. A particulate control device then captures the dry particulate. The captured particles are removed from the system and disposed.

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1 Telephone conversation with Rand Kane and Kyle Shoop, Techint Technologies, on February 7, 2002.

This control option will generate dry solid waste, consisting mainly of lime and $CaSO_4$. This waste must be disposed of in a solid waste landfill, giving this option additional environmental concerns. Removal efficiencies decrease as the amount of sulfur contained in the fuel decreases. Also pipeline quality natural gas contains very little sulfur, thus making any FGD economically infeasible. Based on additional environmental concerns with the FGD solid waste, low sulfur removal efficiencies, and cost to control, FGD is eliminated as a BACT control option.

(4) CO and VOC

Carbon monoxide emissions from boilers are a result of incomplete combustion of natural gas. Improperly tuned boilers operating at off design levels decrease combustion efficiency resulting in increased CO emissions. Control measures taken to decrease the formation of NOx during combustion may inhibit complete combustion, which could increase CO emissions. Lowering combustion temperatures through premixed fuel combustion can be counterproductive with regard to CO emissions. However, improved air/fuel mixing inherent to newer combustor design and control systems limits the impact of fuel staging on CO emissions.

The VOC emissions from natural gas-fired sources are the result of two possible formation pathways: incomplete combustion and recombination of the products of incomplete combustion. Complete combustion is a function of three variables; time, temperature and turbulence. Once the combustion process begins, there must be enough residence time at the required combustion temperature to complete the process, and during combustion there must be enough turbulence or mixing to ensure that the fuel gets enough oxygen from the combustion air. Combustion systems with poor control of the fuel to air ratio, poor mixing, and insufficient residence time at combustion temperature have higher VOC emissions than those with good controls do.

Control Options Evaluated - The following control options were evaluated in this BACT review:

Thermal oxidizer
Catalytic combustion
Flue Gas Recirculation (FGR)
Proper design and operation and good combustion control

Thermal oxidation heats the flue gas to a temperature of 1200 to 2000 degrees Fahrenheit, at which carbon monoxide will burn to produce carbon dioxide. This option has not been used on natural gas fired boilers and therefore, is not a proven technology for this type of application. The low levels of CO and VOC in the exhaust gas stream would likely make this technology ineffective. This option would also require additional natural gas to be combusted and produce secondary emissions, which would be counterproductive. As a result, this option is eliminated as a BACT control option.

Catalytic combustion uses a catalyst bed to burn flue gas at a temperature of 600 to 800 degrees Fahrenheit, causing carbon monoxide to burn and produce carbon dioxide. The catalyst bed contains heavy metals and requires replacement and recycling and/or disposal, which would create unwanted secondary environmental effects. This option would also require additional natural gas to be combusted and produce secondary emissions, which would be counterproductive. As a result, this option is eliminated as a BACT control option.

Flue Gas Recirculation (FGR) incorporates the recirculation of a portion of the flue gas back to the primary combustion zone as a replacement for the combustion air. The recirculated combustion products provide inert gases that lower the adiabatic flame temperature and the overall oxygen concentration in the combustion zone. FGR has been demonstrated to be technically feasible for controlling NOx emissions from natural gas-fired boilers, and has been found to reduce emissions of CO also. This option could be used if found to be economically feasible.

Proper design and operation and good combustion practices are typically used as the methods to reduce CO and VOC emissions from natural gas fired boilers. Burner manufacturers control CO and VOC emissions by maintaining various operational combustion parameters. Fuel conditions, draft, and changes in air can be adjusted to insure good combustion.

Technically feasible control alternatives - The technically feasible control alternatives are ranked in order of effectiveness as follows:

(1) external FGR
(2) good combustion practices

As discussed previously in this BACT document, external FGR has been determined to be economically infeasible.

Existing BACT Emission Limitations - The EPA RACT/BACT/LAER Clearinghouse (RBLC) is a database that provides emission limit data for industrial processes throughout the United States. IDEM and SDI searched for other permits for vacuum tank degassing systems at other mills. Most other degassing systems vent emissions from the degasser and the boiler to separate stacks. However, it appears that other states have not examined degassing systems with the same level of scrutiny that IDEM is applying to SDI's planned vacuum degassing system. Many of the other degassing systems do not even have permit limits separate from the permit limits for other facilities at the plant. IDEM and SDI did not find any stack test results for emissions from any degasser stacks. IDEM and SDI are not aware of any other degassing system that utilizes a configuration similar to the one planned for the Whitley facility. The information available on vacuum tank degasser systems is summarized in the table below.

Company	NOx	CO	Notes
SDI Whitley County, IN; proposed vacuum degasser boiler, capacity 41.8 MMBtu/hr	0.04 "ultra" Low-NOx burners	0.084	
CSC Limited, Warren, OH	N/A	4 lb/hr from degasser stack only, flare on degasser stack	vacuum degasser at copper weld facility; no longer operating
Republic Technologies, Canton, OH	N/A	estimated 0.61 lb/hr from degasser only (not a permit limit)	degasser exhausts into meltshop baghouse so there are no permit limits specific to just the degasser
Oregon Steel, Portland, OR	N/A	N/A	Source has a PAL, so no specific limits on just the degasser. No stack testing on degasser.

Company	NOx	CO	Notes
SDI Whitley County, IN; proposed vacuum degasser boiler, capacity 41.8 MMBtu/hr	0.04 "ultra" Low-NOx burners	0.084	
Rocky Mountain Steel, Pueblo, Colorado; permit numbers 93PB1073-1 and 93PB1073-2.	100 lb/MMCF for boiler stack; 100 lb/MMCF for degasser stack; equivalent to a total of 0.1 lb/MMBtu for both combined	84 lb/MMCF for boiler stack; 2.57 tons/yr for degasser stack; equivalent to a total of 0.118 lb/MMBtu for both combined	no stack testing performed
Charter Steel, Saukville, WI; electric powered degasser.	N/A	N/A	Degasser is electric powered, does not use boiler to draw vacuum. Degasser exhausts to meltshop baghouse, so there are no limits specific to just the degasser.
Nucor Steel, Norfolk, Nebraska	N/A	N/A	permits do not include any limits for degasser.
North Star Steel, Monroe, MI	N/A	N/A	Degasser is part of ladle refining station. Limits are written for ladle refining station (includes many other processes), so no information available on emissions from just the degasser.

Since IDEM and SDI were not able to find another degassing system with a configuration similar to the one planned for the SDI Whitley facility, IDEM compared the proposed limits for the degasser boiler to those of other natural gas-fired boilers. The database for boilers contains many entries. The table below includes some of the entries of the more stringent limitations. The table also includes information IDEM gained from other regulatory agencies, other IDEM permits, permits issued by other regulatory agencies, and information from vendors/suppliers.

Company	Facility	PM / PM10	NOx	CO	VOC	SO_2	Stack Testing / Notes
SDI Whitley County, IN	proposed vacuum degasser boiler, capacity 41.8 MMBtu/hr	0.0076	0.04 “ultra” Low-NOx burners	0.084	0.0026	0.0006	
Darling International, Fresno, CA	Nebraska Boiler, capacity 31.2 MMBtu/hr	0.0137 LAER	0.036, low-NOx burner and FGR, LAER	0.089 LAER	0.0028	0.0021	required for NOx and CO Test conducted Nov 3, 1998 Low Fire NOx: 28.54 ppm, 0.034 lb/MMBtu CO: 6.85 ppm, 0.005 lb/MMBtu High Fire NOx: 29.16 ppm, 0.035 lb/MMBtu CO: 5.94 ppm, 0.004 lb/MMBtu
Aire Liquide America Corporation, Geismar, LA permit number PSD-LA-622, issued February 1998, located in Ascension Parrish	natural gas boiler #1, max capacity 95 MMBtu/hr	0.01	0.05, low NOx burners	0.06	0.0026	0.0006	permit reviewer was Dan Nguyen (pronounced Win) 225-763-3956 permit requires stack test for CO and NOx Test conducted Aug 24, 1999 PM10: 0.00334 SO_2: 0.00042 NOx: 0.03722 CO: 0.00074 VOC: 0.00010
Mid-Georgia Cogen, Kathleen, GA	boiler, 60 MMBtu/hr	0.005	0.107, dry low NOx burner and FGR	0.05	0.005		required for NOx and CO while burning natural gas and fuel oil Test conducted Oct 26, 2000 NOx: 0.056 lb/MMBtu

Company	Facility	PM / PM10	NOx	CO	VOC	SO_2	Stack Testing / Notes
SDI Whitley County, IN	proposed vacuum degasser boiler, capacity 41.8 MMBtu/hr	0.0076	0.04 "ultra" Low-NOx burners	0.084	0.0026	0.0006	
Nucor, Crawfordsville, IN permit number 107-2764 issued Nov 30, 1993	Vacuum degasser boiler, max cap 34 MMBtu/hr	3 lb/MMCF	200 MMCF low NOx burners	35.0 lb/MMCF	2.8 lb/MMCF		none required by permit. The vacuum degasser emissions do not exhaust to the boiler.
Duke Vigo, IN Permit number 167-12481, issued June 6, 2001	boiler, max cap 46.6 MMBtu/hr	0.007	0.049, low NOx burners	0.082	0.0054		
Southern Energy, Inc.	boiler 35 MMBtu/hr	0.008	0.048, low NOx burners				
Crockett Cogeneration, Crockett, CA	3 auxiliary boilers, each with max capacity 40,000 lb steam/hr		8.2 ppm at 3% O_2, SCR, LAER	11.0			Test conducted June 1997 NOx: 5.47 ppm CO: 3.24 ppm Test conducted June 1998, NOx: 5.39 ppm, 0.0065 lb/MMBtu CO: 6.02 ppm, 0.0045 lb/MMBtu PM10 (only filterable): 0.0029 lb/MMBtu

Company	**Facility**	**PM / PM10**	**NOx**	**CO**	**VOC**	**SO_2**	**Stack Testing / Notes**
SDI Whitley County, IN	proposed vacuum degasser boiler, capacity 41.8 MMBtu/hr	0.0076	0.04 “ultra” Low-NOx burners	0.084	0.0026	0.0006	
Federal Bureau of Prisons - Victorville, CA	boilers #1 and #2, natural gas with diesel fuel backup, max cap 20 MMBtu/hr		5 ppmv @ 3% O_2 low NOx burners and FGR and SCR, LAER				NOx CEMs required and NOx testing Testing conducted Oct 12 & 13, 2000 NOx: 3.82 ppm, 0.046 lb/hr
U.S. Borax, Wilmington, CA	30 MMBtu/hr natural gas boiler		Radian Rapid mix burners, LAER				Test conducted Dec 21, 1995 NOx: 0.0092 lb/MMBtu CO: 0.024 lb/MMBtu
Qualitech Steel Corporation, IN	50.21 MMBtu/hr vacuum degasser boiler		81 lb/MMCF (equivalent to 0.08 lb/MMBtu)				Test conducted Sept 7, 1999 NOx: 10.9 lb/MMCF The degasser emissions to not exhaust to the boiler.

PM/PM10 BACT

As shown in the above table, the BACT for PM/PM10 for other natural gas fired boilers is combustion control. All of the above listed facilities use a fuel specification of natural gas or good design and operation (i.e. good combustion). As stated above PM/PM10 emissions from natural gas fired sources are low, making add on PM/PM10 control both economically and technically infeasible. IDEM did not find any facilities that use add-on controls for controlling PM/PM10 emissions from small natural gas fired boilers. Other facilities have been issued permits requiring lower PM/PM10 limits than those proposed by SDI. However, none of these lower limits have been demonstrated to be achieved in practice for any other natural gas fired boiler of comparable size. The boilers at Crockett Cogeneration demonstrated compliance with a lower limit. The test results determined PM emissions of 0.0029 lb/MMBtu, but this test only measured filterable PM. Since the emissions are a result of combustion, a significant portion of the PM emissions are expected to be emitted as condensible PM10. As a result the Crockett Cogeneration test is not useful in setting a PM10 limit for the proposed SDI boiler. Additionally, the boilers at Crockett Cogeneration are much larger boilers than the one proposed by SDI. The limit proposed by SDI is equivalent to the AP-42 emission factor. No other lower total particulate limit has been demonstrated to be achieved in practice for any other natural gas fired boiler of comparable size.

Conclusion - Based on the information presented above the PM/PM10 BACT for the boiler is good combustion practices, and the use of natural gas or propane as fuel. The PM/PM10 emissions shall not exceed 0.0076 lb/MMBtu, which is equivalent to 0.318 pound per hour.

NOx BACT

Most of the other boilers of similar size that have demonstrated compliance with lower NOx limits use either SCR or FGR to reduce NOx emissions. As discussed above, both SCR and FGR have been determined to be economically infeasible for the proposed boiler at SDI. Many of the other facilities that use SCR or FGR were required to comply with LAER, which does not take into account the cost of the control.

SDI proposed the lowest NOx limit achieved in practice for a boiler using this type of technology (ultra low NOx burners) to reduce NOx emissions. While NOx emissions from natural gas fired boilers can be accurately predicted, it is not clear what effect (if any) the degassing emissions will have on the emissions from the boiler’s stack. SDI and IDEM have been unable to identify any other source operating a degasser with a similar configuration[2]. Since SDI and IDEM cannot be sure of what effect (if any) the degassing emissions would have on the NOx emissions from the boiler, the NOx limit will be written with a “re-opener” clause. This will allow IDEM to increase or decrease the NOx limit based on the results of the initial performance test.

Conclusion - Based on the information presented above, the NOx BACT shall be the use of “ultra” low NOx burner design in conjunction with a fuel specification of natural gas or propane. The NOx emissions from the boiler shall not exceed 0.04 lb/MMBtu, which is equivalent to 1.67 pounds per hour. Since SDI and IDEM cannot be sure of what effect (if any) the degassing emissions would have on the NOx emissions from the boiler, the NOx limit will be written with a “re-opener” clause. This will allow IDEM to increase or decrease the NOx limit based on the results of the initial performance test. Regardless of the results of the initial stack test, SDI will be required to fully optimize the combustion

[2] SDI and IDEM have both found that other sources have a separate stack for the degasser and use a flare to reduce the CO emissions from the degasser stack. SDI believes this is wasteful and likely results in higher total emissions.

system in order to decrease NOx emissions as much as possible.

SO_2 BACT

IDEM did not find any facilities that use add-on controls for controlling SO_2 emissions from small natural gas fired boilers. All similar facilities require low sulfur fuel as the method for achieving BACT. IDEM found very few SO_2 limits for other small natural gas fired boilers. The limit proposed by SDI is equivalent to the AP-42 emission factor. No other lower limit has been demonstrated to be achieved in practice for any other natural gas fired boiler of comparable size. Therefore, the very low SO_2 emission rate that results from the use of natural gas or propane as fuels represents BACT for SO_2 emissions from the boiler.

Conclusion - Based on the information presented above, the SO_2 BACT shall be the use of propane or natural gas (less than 0.8 percent sulfur by weight) which is inherently low in sulfur, and good combustion practices. The SO_2 emission limit from the boiler shall not exceed 0.0006 lb/MMBtu, which is equivalent to 0.025 pound per hour.

CO BACT

All of the entries listed in the above table list good combustion practice and good design/operation as CO BACT. As stated above CO emissions are a result of incomplete combustion of natural gas. One facility, Mid-Georgia Cogen, has demonstrated compliance with a lower CO limit than that proposed by SDI; however, Mid-Georgia Cogen uses FGR to reduce combustion emissions. Since FGR has been determined to be economically infeasible for use in the proposed vacuum degasser boiler at SDI, the limit for Mid-Georgia Cogen is not considered achievable.

While CO emissions from natural gas fired boilers can be accurately predicted, it is not clear what effect (if any) the degassing emissions will have on the emissions from the boiler’s stack. SDI and IDEM have been unable to identify any other source operating a degasser with a similar configuration. Since SDI and IDEM cannot be sure of what effect (if any) the degassing emissions would have on the CO emissions from the boiler, the CO limit will be written with a “re-opener” clause. This will allow IDEM to increase or decrease the CO limit based on the results of the initial performance test.

Conclusion - Based on the information presented above, the CO BACT shall be the use of good combustion practice. Emissions from the boiler shall not exceed 0.084 lb/MMBtu, which is equivalent to 3.51 pounds per hour. Since SDI and IDEM cannot be sure of what effect (if any) the degassing emissions would have on the CO emissions from the boiler, the CO limit will be written with a “re-opener” clause. This will allow IDEM to increase or decrease the CO limit based on the results of the initial performance test.

VOC BACT

All of the entries listed in the above table list good combustion practice and good design/operation as VOC BACT. The VOC emission limit (0.0026 lb/MMBtu) for Aire Liquid America in Geismar, LA is the lowest limit demonstrated to be achieved in practice. The Aire Liquid America facility uses low NOx burners and good combustion practices to reduce combustion emissions. Therefore, BACT is proposed as a limit of 0.0026 lb/MMBtu, to be achieved through proper design and operation and using good combustion practices.

Conclusion - Based on the information presented above, the VOC BACT for the boiler shall be proper design and operation, and good combustion practices. Emissions from the boiler shall not exceed 0.0026 lb/MMBtu, which is equivalent to 0.11 pound per hour.

Appendix C

Addendum to Air Quality Analysis provided for CP 183-12692-00030

Introduction

Steel Dynamics has applied to modify their permit by adding a Ladle Vacuum Degasser (LVD) to their existing plant near Columbia City in Whitley County, Indiana. Whitley County is designated as attainment for all of the National Ambient Air Quality Standards.

Additional modeling was received by the Office of Air Quality (OAQ) on December 17, 2001 This document provides Modeling Section's review including an air quality analysis performed by the OAQ.

Air Quality Analysis Objectives

The OAQ review of the air quality impact analysis portion of the permit application will accomplish the following objectives:

A. Establish which pollutants require an air quality analysis based on the source’s emissions.
B. Determine the ambient air concentrations of the source's emissions and provide analysis of actual stack height with respect to Good Engineering Practice (GEP).
C. Demonstrate that the source will not cause or contribute to a violation of the National Ambient Air Quality Standard (NAAQS) or Prevention of Significant Deterioration (PSD) increment.

Summary

Steel Dynamics has applied to modify their permit by adding a Ladle Vacuum Degasser (LVD), to their existing plant near Columbia City in Whitley County, Indiana. Whitley County is currently designated as attainment for all criteria pollutants. Nitrogen Dioxide (NO2), Sulfur Dioxide (SO2), Lead, Carbon Monoxide (CO) and Particulate Matter less than 10 microns (PM10) emission rates associated with all the emission units at the plant (including the proposed new LVD boiler) exceeded their respective significant emission rates. Modeling results taken from the LVD were added to the previous permit modeling using Industrial Source Complex Short Term (ISCST3) model. When the LVD impacts were added to the original modeling results, no new significant monitoring de minimis levels were found to be exceeded. The PM10, NO2 and SO2 increments and all air quality standards were found to be maintained. Hazardous Air Pollutants (HAPS) are far from approaching one-half of one percent of the Permissible Exposure Limit (PEL). There was no impact review conducted for the nearest Class I area, which is Mammoth Cave National Park in Kentucky, due to its large distance from the source.

<u>Part A - Impact Analysis</u>

An air quality analysis, including air dispersion modeling, was performed to determine the maximum concentrations of the source emissions on receptors outside of the facility property lines. Long-term (annual) worst-case determinations were based on 8760 hours of operation per year, while short-term were based on maximum pound/hour emission rates. Fuel usage limits in the permit will effectively limit operations to less than 8760 hours per year; however, to provide a conservative air quality analysis, worst-case determinations were still based on 8760 hours per year of operation.

Model Description

The Office of Air Quality review used the Industrial Source Complex Short Term (ISCST3) model, Version 3, dated June 4, 1999 to determine maximum off-property concentrations or impacts for each pollutant. All regulatory default options were utilized in the United States Environmental Protection

Agency (U.S. EPA) approved model, as listed in the 40 Code of Federal Register Part 51, Appendix W "Guideline on Air Quality Models". The model also utilized the Schulman-Scire algorithm to account for building downwash effects. Stacks associated with the proposed LVD boiler are below the Good Engineering Practice (GEP) formula for stack heights. This indicates that wind flow over and around surrounding buildings can influence the dispersion of pollutants coming from the stacks. 326 IAC 1-7-3 requires a study to demonstrate that excessive modeled concentrations will not result from stacks with heights less than the GEP stack height formula. These aerodynamic downwash parameters were calculated using U.S. EPA's Building Profile Input Program (BPIP).

Meteorological Data

The meteorological data used in the ISCST3 model consisted of surface data from the Fort Wayne National Weather Service station merged with the mixing heights from Dayton, Ohio for the five-year period (1990-1994). The 1990-1994 meteorological data was purchased through the National Oceanic and Atmospheric Administration (NOAA) and National Climatic Data Center (NCDC) and preprocessed into ISCST3 format with an updated version of U.S. EPA's PCRAMMET program.

Modeled Results

Maximum modeled concentrations for each pollutant over its significant emission rate are listed below in Table 1 and are compared to each pollutant's significant impact increment for Class II areas, as specified by U.S. EPA.

TABLE 1 - Summary of Significant Impact Analysis (ug/m3)

Pollutant	Time Averaging Period	Maximum Modeled Impacts	New Boiler	Total	Significant Impact Increments	Significant Monitoring Increments
CO	1-hour	1812.5	98.0	1910.5	**2000.0**	[a]
CO	8-hour	446.1	21.4	467.5	**500.0**	575
SO_2	3-hour	48.8	0.2	49.9	**25.0**	[a]
SO_2	24-hour	9.3	0.1	9.4	**5.0**	13.0
SO_2	Annual	0.3	0.01	0.31	**1.0**	[a]
PM_{10}	24-hour	16.4	0.8	17.2	**5.0**	10.0
PM_{10}	Annual	2.6	0.1	2.7	**1.0**	[a]
NO2	Annual	5.0	0.6	5.6	**1.0**	14.0
Lead	Quarterly	.001	.000009	.001	**--**	0.1

[a] No limit exists for this time-averaged period

Adding the LVD modeling results to the previous modeling results, have a significant impact for SO2 on a 3-hour and 24-hour basis, for NO2, and for PM10 on a 24-hour and annual basis. This is conservative as peak impacts will not necessarily pair up in time or space, but would likely be less than the sum of the two.

Nitrous Oxides

Since modeled concentrations for NO2 were above significant impact, modeling was performed to determine total increment consumption and to demonstrate compliance with the NAAQS. The monitoring site used was Butler in DeKalb county. The modeling results in Table 2 show that the increment as well as the National Ambient Air Quality Standard for Nitrous Oxides is maintained.

Table 2 - NO2 Modeling Results (ug/m3)						
LVD Impact	Increment Consumed	Available Increment*	Modeled NAAQS Total	Monitored Value	Total NO2	NO2 Standard
0.6	5.6	20	5.8	16.9	22.7	100

* Indiana allows a source to consume a maximum of 80% of the remaining 25 ug/m3 NO2 increment

PM10

Since modeled concentrations for PM10 were above significant impact, modeling was performed to determine total increment consumption and to demonstrate compliance with the NAAQS. The monitor used was the Allen County Motors site. The modeling results in Table 3 show that the increment as well as the National Ambient Air Quality Standard for PM10 is maintained.

Table 3 - PM10 Modeling Results (ug/m3)						
LVD Impact	Total Increment Consumed	Available Increment*	Modeled NAAQS Total	Monitored Value	Total PM10	PM10 Standard
0.1	2.7	17	3.0	28.0	31.0	50 (Annual)
0.8	14.2	30	14.5	56.3	70.8	150 (24-hr)

* Indiana allows a source to consume a maximum of 80% of the remaining PM10 increment on a point-by-point basis. At no point has more than 80% of the existing increment been consumed. The project's area of peak impact does not coincide with the LVD project's area of total peak increment.

Sulfur Oxides

Since modeled concentrations for SO2 were above significant impact, modeling was performed to determine total increment consumption and to demonstrate compliance with the NAAQS. The monitor used was the monitor of Butler in DeKalb county. The modeling results in Table 4 shows that the increment as well as the National Ambient Air Quality Standard for sulfur dioxide is maintained.

Table 4 - SO2 Modeling Results (ug/m3)						
Project Impact	Increment Consumed	Available Increment*	Modeled NAAQS Total	Monitored Value	Total SO2	SO2 Standard
0.2	0.31	20	0.31	7.9	8.21	80
0.1	8.4	91	8.4	33.2	41.6	365
0.01	37.1	512	37.2	73.4	110.6	1300

* Indiana allows a source to consume a maximum of 80% of the remaining SO2 increment

HAPS

OAQ ran the ISCST3 model for all HAPs. Maximum 8-hour concentrations were determined and the concentrations were recorded as a percentage of each HAP Permissible Exposure Limit (PEL). The PELs were established by the Occupational Safety and Health Administration (OSHA). In Table 5 below, the results of the HAP analysis with the emission rates, modeled concentrations and the percentages of the PEL for each HAP are listed. All HAPs concentrations were modeled below 0.5% of their respective PELs. The 0.5% of the PEL represents a safety factor of 200 taken into account when determining the health risk of the general population. The impact of the LVD on HAP concentrations are much less than 0.01 percent of the PEL. Thus, the LVD will not adversely have an adverse impact on HAP concentrations.

Table 5 HAP's Modeling Summary

HAP	New Boiler Concentration (ug/m3)	OSHA PEL (ug/m3)	Percent of PEL
Benzene	5.350e-07	3.20	1.670e-05
Formaldehyde	1.910e-05	0.93	2.050e-03
Hexane	4.580e-04	1800	2.540e-07
Napthalene	1.550e-07	50	3.100e-07
Toluene	8.650e-07	750	1.150e-07
Antimony	0.000e+00	0.50	0.000e+00
Arsenic	5.100e-08	0.01	5.100e-04
Beryllium	3.060e-09	0.002	1.530e-04
Cadmium	2.800e-07	0.005	5.600e-03
Chromium	3.570e-07	0.50	7.140e-05
Cobalt	2.140e-08	0.10	2.140e-05
Lead	1.270e-07	0.05	2.540e-04
Manganese	9.690e-08	5.00	1.940e-06
Mercury	6.640e-08	0.10	6.640e-05
Nickel	5.350e-07	1.00	5.350e-05
Selenium	6.100e-09	0.20	3.050e-06